Training Programme on
PLANNING FOR THE POWER SECTOR

Mughal Sheraton, Agra
December 9-13, 1991

READING MATERIAL

in collaboration with

Central Electricity Authority
New Delhi

Power Finance Corporation
New Delhi

The Commission of the European Communities
Brussels

organised by
Tata Energy Research Institute
New Delhi

Training Programme on
Planning for the Power Sector
in collaboration with
Central Electricity Authority
and
Power Finance Corporation

Hotel Mughal Sheraton - Agra
9-13 December 199~~0~~1

9 December 1991

1000-1130	Inaugural session presided by Shri Krishna Swarup, Chairman, Central Electricity Authority Inaugural address: Shri S. Rajgopal, Secretary, Department of Power
1130-1145	Coffee Break
1145-1300	Electric Power and Economic Development R.K. Pachauri
1300-1430	Lunch
1430-1540	Innovative Techniques in Power Sector Planning Kapil Thukral
1540-1600	Coffee Break
1600-1710	Electricity Pricing Issues Bhaskar Natarajan and Bhavna Bhatia
1710-1800	Demonstration of Software for Generation Expansion Model

10 December 1991

0930-1040	The Power Sector in Germany - I Ulrich Koch
1040-1155	The Power Sector in Germany - II Ulrich Koch
1155-1215	Coffee Break
1215-1325	Experiences in Power Sector in Denmark - I P. Nielsen
1325-1430	Lunch
1430-1540	Experiences in Power Sector in Denmark - II P. Nielsen
1540-1600	Coffee Break

1600-1710	Panel discussion on developed country experiences

11 December 1991

0930-1040	Strategies for Increasing Generation from Existing Thermal Plants R.K. Gupta
1040-1155	Supply Options for the Eighth-Plan and Beyond M.I. Beg
1155-1215	Coffee break
1215-1325	Issues in Electricity Subsidy to Agriculture Sector M.P. Gulati
1325-1430	Lunch
1430-1540	Environmental Concerns in Power Sector D. Luthra
1540-1600	Coffee break
1600-1710	Environmental Impact of Thermal Power Stations : A Case Study S. Chary

12 December 1991

0830-0940	Strategies for Reducing T & D Losses L.R. Suri
0940-1050	Problems of Integrated Grid Operation and Their Comprehensive Solution Bhanu Bhushan
1050-1100	Coffee break
1100-1210	Panel discussion on T & D issues

Outing

13 December 1991

0900-1000	Power Sector in SAARC countries Bhavna Bhatia
1000-1100	Distribution Planning and Management P.D. Sharma
1100-1115	Coffee break
1115-1215	Energy Conservation and Electricity Boards Bhaskar Natarajan and Satish Sabharwal
1215-1330	Valedictory Session: Address by Shri I.M. Sahai, Chairman, Power Finance Corporation
1330	Lunch

Training Programme on
Planning for the Power Sector

Hotel Mughal Sheraton, Agra

December 9-13, 1991

List of Faculty

External Faculty

1. Mr. Krishna Swarup,
   Chairman,
   Central Electricity Authority,
   Sewa Bhavan,
   R.K. Puram,
   New Delhi.

2. Mr. M.I. Beg,
   Member (Planning),
   Central Electricity Authority,
   Sewa Bhavan,
   R.K. Puram,
   New Delhi.

3. Mr. G.V. Rao,
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4. Mr. R.K. Gupta,
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   Power Finance Corporation Ltd.,
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   Janpath,
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6. Mr. I.M. Sahai,
   Chairman and Managing Director,
   Power Finance Corporation Ltd.,
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10. Mr. Ulrich Koch,
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TERI Faculty

1. Dr. R.K. Pachauri
2. Dr. Bhaskar Natarajan
3. Ms. Bhavna Bhatia
4. Dr. Kapil Thukral
5. Dr. Damyant Luthra
6. Mr. V. Srinivasachary
7. Mr. P.D. Sharma

Background Material for the Session on

ELECTRIC POWER & ECONOMIC DEVELOPMENT

Dr. R.K. Pachauri
Director
Tata Energy Research Institute
New Delhi

Training Programme on
Planning for the Power Sector

December 9-13, 1991

Innovations in Electrical Appliances

- Electric Motor
- Incandescent Bulb
- Television Set

Dualistic Form of Development

- Urban-Rural Divide

Growth of Power Generation Capacity in India

- 2300 MW in 1950
- Over 70 Thousand MW in 1991
- Sectoral Changes in Consumption.

Welfare Aspects of Power Consumption

Energy - GDP Relationship

Impact of New Technologies

Time Path of Energy - GDP Relationship

Pre-requisites for Efficiency Gains

Viability of Rural Electrification Schemes
- Mobilization Matching Inputs
- local Skills and Training

Importance of Community Participation

Democracy and Rural Energy Development

Participatory Research and Empowerment of Poor Communities.

Variable Nature of Energy - Development Linkages

Subsidies

Centralised Power Supply and Local Decision Making

Technology Changes and Decentralised Power Options

Numerical Targets v/s Economic Welfare

Viability of Renewable Energy Options

Efficiency Gains in Industrial and Organised Sectors

Inevitability of Increased Energy Intensity in Rural Areas

New Paradigms

Institutional Structures and Conditions

Equity Issues in Rural Electrification

Figure 1

ASPECTS OF ENERGY EFFICIENCY

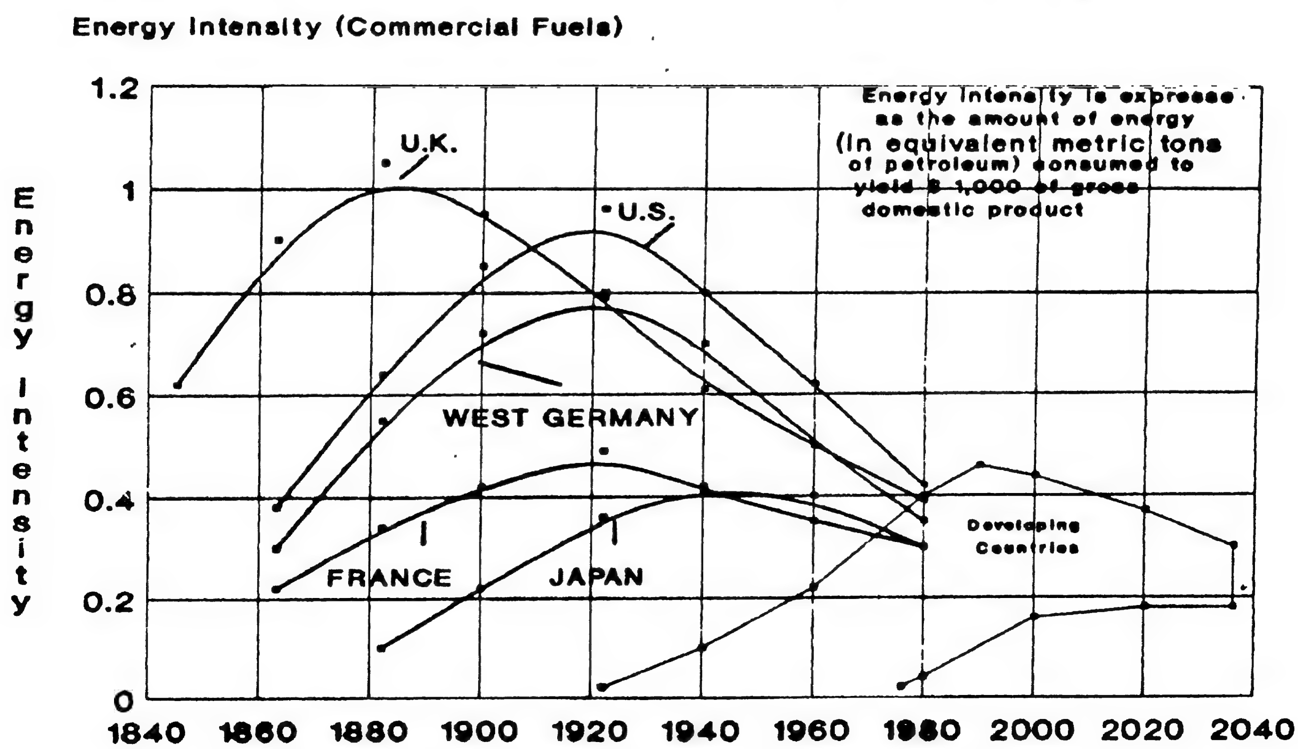
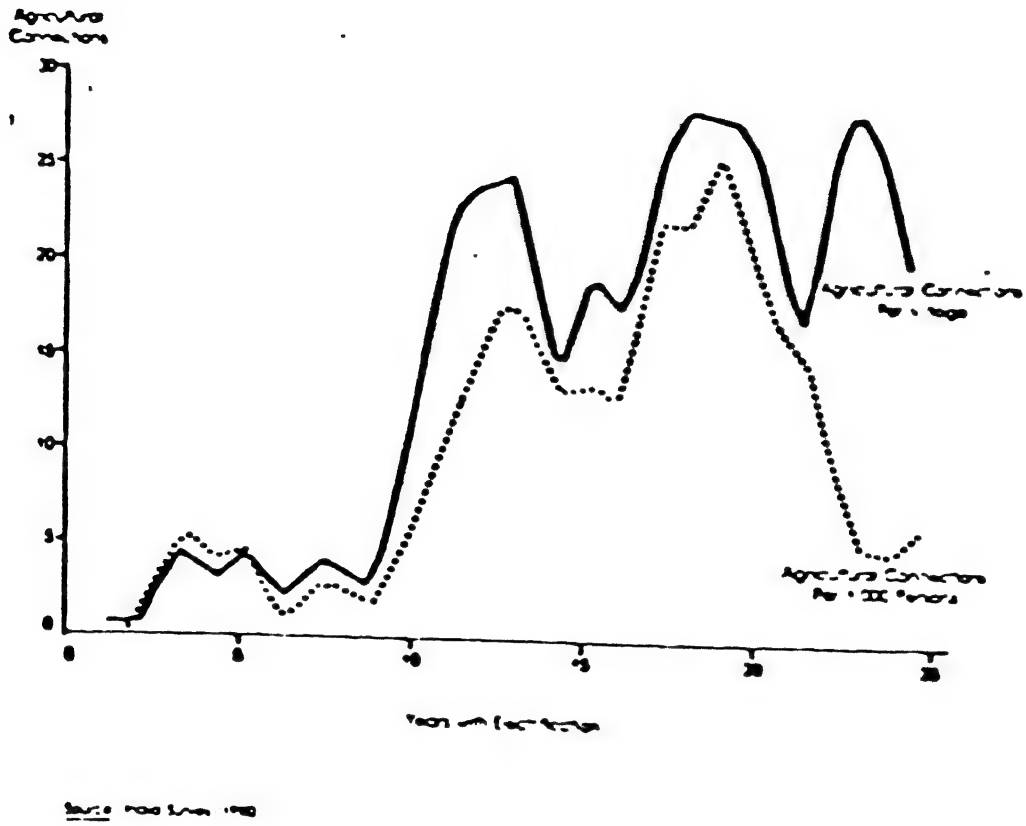


Figure 2

Agricultural Connections by
Village Year of Electrification, 1980
(3 Year Moving Averages for
Villages in 1980 Sample)



Source: Barnes, Douglas F., Electric Power for Rural Grov h, Westview Press, Colorado, U.S.A., 1988 (1).

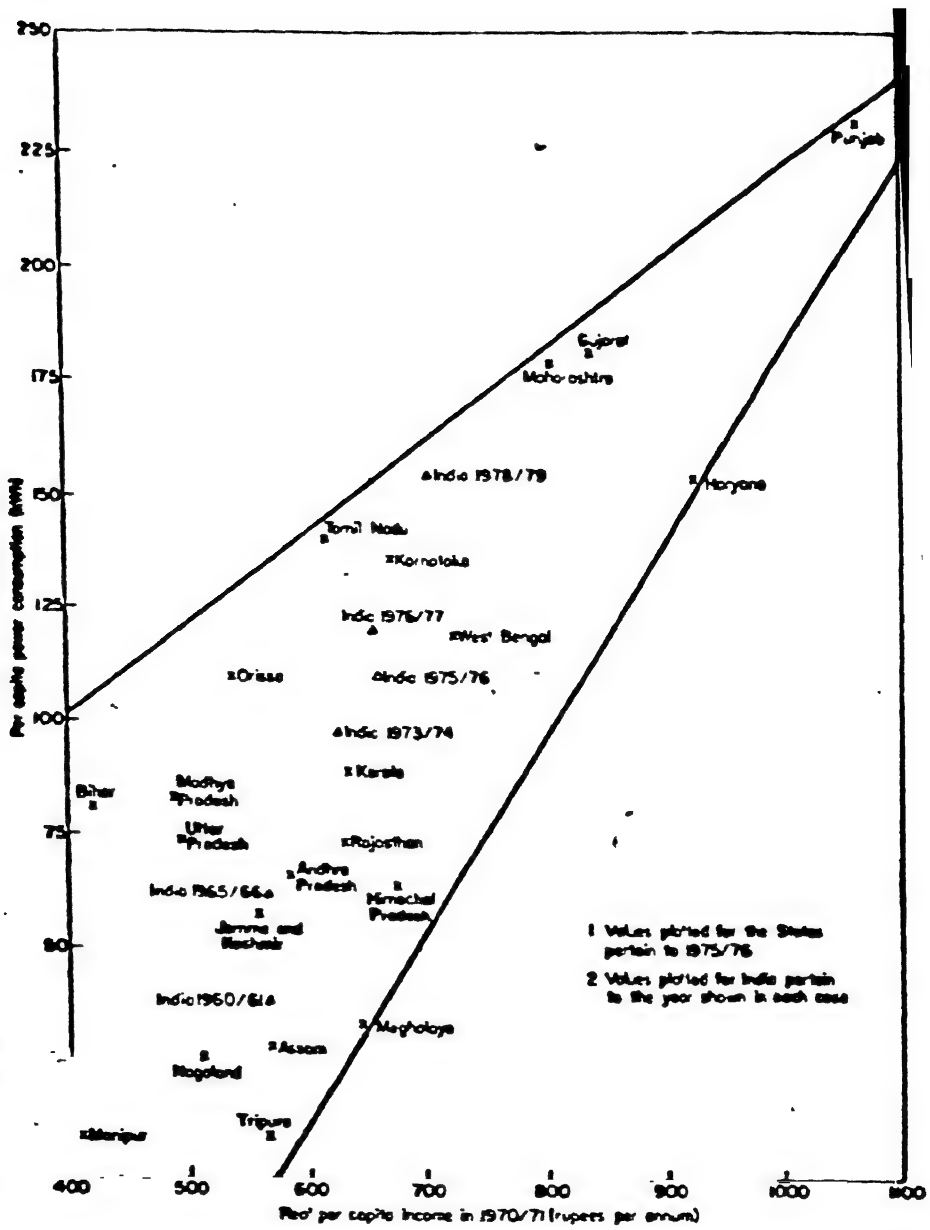
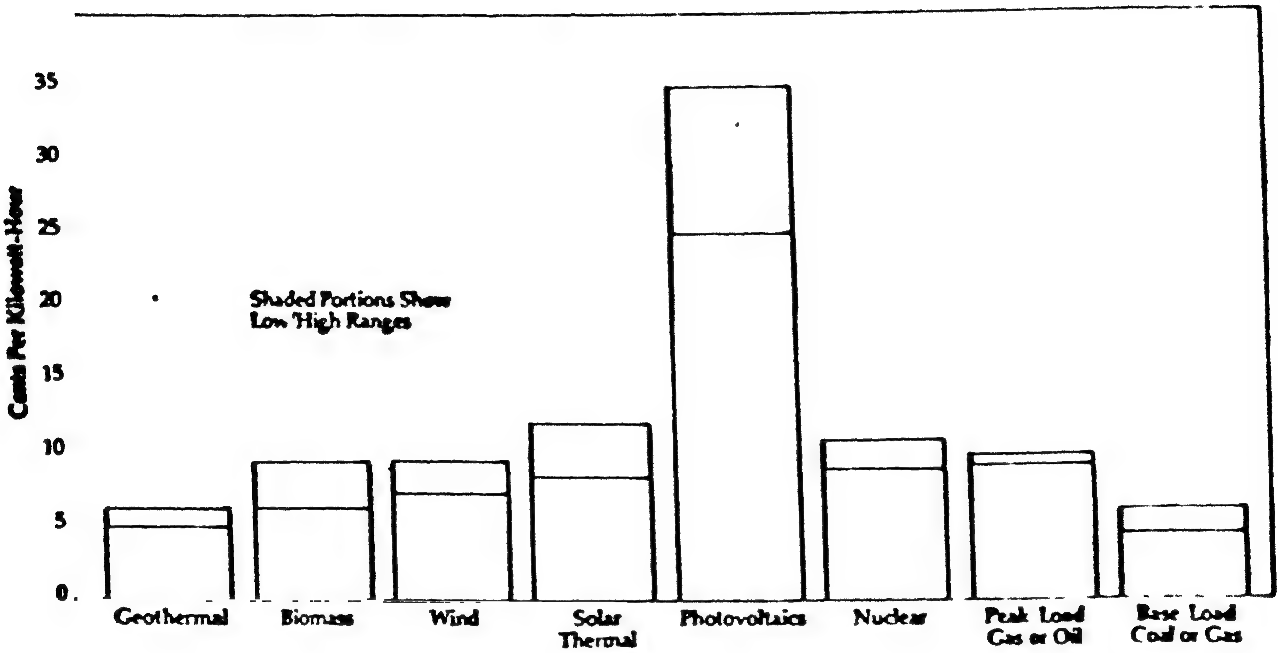


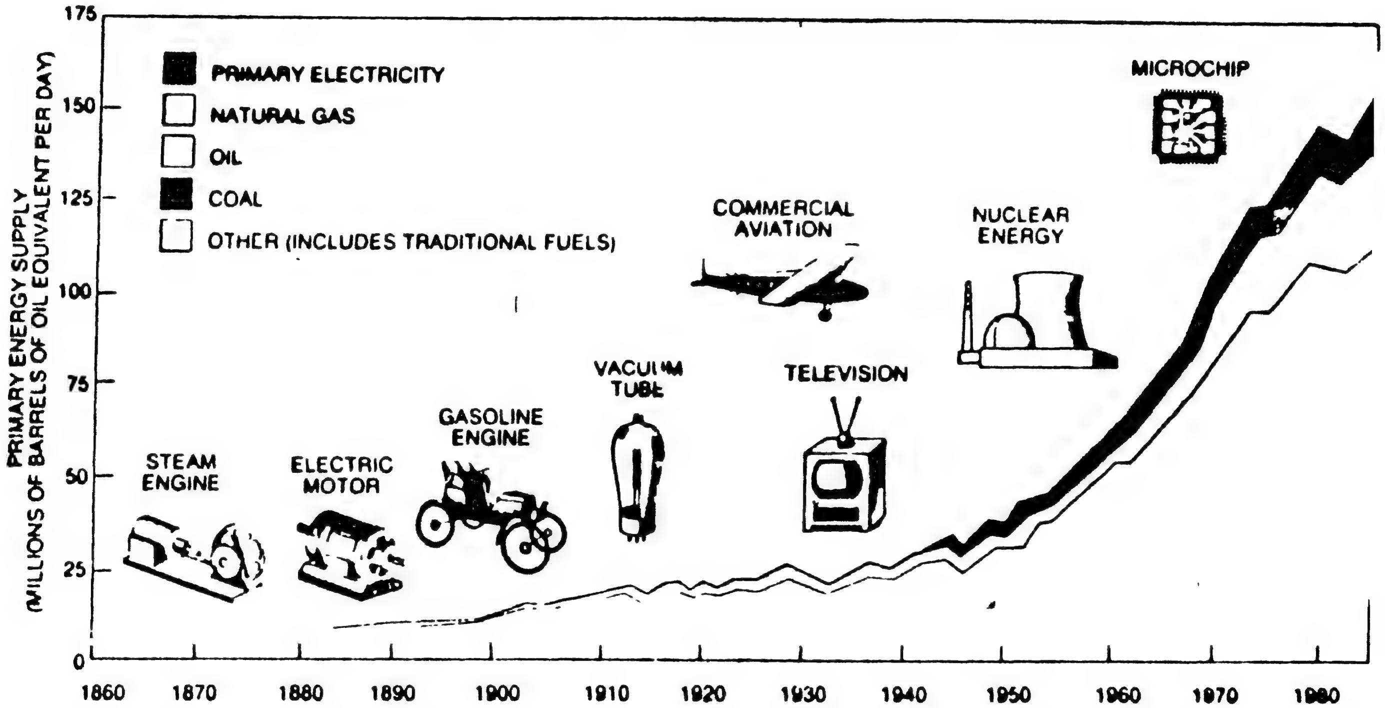
Figure 5. Relationship between per capita income and per capita power consumption in India.

For all states in 1975/76 and India for selected years.

Figure 4 Electricity Costs for New Generating Capacity



Source. United States Department of Energy, (1990)



RATE OF PRIMARY ENERGY USE and the relative contributions of different sources reflect the evolution of technology as well as the growth of the human population. The rapid rise of oil after World War II, for example, is indicative of the rise of mass transportation and industry. Similarly, the growth of electricity in the late 1960's parallels the rise of a services-oriented economy. Although fossil fuels still dominate the primary energy supply, coal's share peaked around 1920, when it provided more than 70 percent of all the fuel consumed; oil's share peaked in the early 1970's at slightly more than 40 percent. Natural gas, which is less polluting than either oil or coal, is expected to contribute more to global energy use.

POWER SYSTEM PLANNING

(A Gaming Approach)

Kapil Thukral
Bhavna Bhatia
M. Karuppasamy

Annual Power Sector Training Programme
Agra

December 9-13, 1991

1. Introduction

Electricity is a high-quality form of energy with diverse and increasing applications. In several countries, including India, electricity has been and is one of the fastest growing sectors. Electricity has also accounted for a major share of public sector investments in the past two decades or so. Despite this, electricity demand continues to outstrip supply in India, and power shortages continue to exist. These facts become clear from data presented in Tables 1 and 2.

Owing to these circumstances, it is clear that planning for the electricity sector needs more attention than has been given in the past.

2. The Necessity of a Gaming Approach

Until now, electric power planning has been largely the reserve of the Central Electricity Authority (CEA) and the Planning Commission of the Government of India. The CEA has used optimization models like WASP-III (Wien Automatic Systems Planning) and EGEAS (Electricity Generation Expansion Analysis System) packages. The very fact that the results obtained from the EGEAS model, published in 1987, are no longer even considered realistic, is an indication of some drawbacks in the power system expansion planning process.

Yet electricity is perceived as being an infrastructural good. However, the perceptions on how electricity is an "infrastructural good" differs between the various actors in the

planning process. The CEA (and the state utilities and the central sector corporations like NTPC, NLC, NHPC etc.) are of the view that an adequate and a reliable power supply is an essential prerequisite to economic and social development. The Planning Commission, on the other hand, emphasizes that the requirement of electricity is a result of economic activity and social progress, and that the demand for electricity is a consequence of resource availability, investment patterns and other factors extraneous to the power industry. This dichotomy of attitudes needs to be resolved before realistic power demand forecasts and supply expansion plans are made.

It is clear by now that the power system planning process should consider factors beyond generation, transmission and distribution. Demand side issues and environmental impacts have already been identified as important concerns in the electric power system planning process. Similarly, electricity tariffs and the financial resource situation of the concerned electric power utilities also need to be considered. After all, financial resource constraints have often resulted in time over-runs and concommittant cost over-runs in commissioning new power generation capacity -- which have further aggravated the financial crunch of the power utilities.

As the issues necessary to consider in the planning process are very diverse, it is difficult to accomodate all of them in an optimization framework. A simulation approach may be a better alternative, in which the consequences of incremental investments

on the supply side can be assessed against similar investments to contain rising demand or mitigating the environmental consequences of enhancing power supplies. A simulation framework thus facilitates an analysis of various investment options and trade-offs.

If the simulation framework is computerized and made interactive and user-friendly, it provides for a gaming approach to power systems planning. The user can develop his own power system expansion strategies and pursue growth strategies in various directions (e.g. high conservation, low conservation, no conservation, minimal carbon-dioxide emissions, maximum indigenous energy resource use, and so forth). Based on the outcomes given by pursuing such strategies over a fairly long time horizon (say 20 to 30 years), the user would then be in a better position to decide on a suitable growth strategy -- or what policy initatives would lead to a desirable, sustainable growth strategy.

3. The Simulation Approach

From the previous discussion, it becomes clear that certain variables are -- at least to some extent -- amenable to management or policy control. These may be called as "soft" variables, compared to others which are exogenous or "hard". In addition, there are other variables upon which the user can decide -- these are referred to as decision variables. The distinction is often not rigid; nevertheless, it facilitates a convenient nomenclature to distinguish between what is to be held "fixed" and what is open to discussion and opinion.

The three types of variables may be described as follows:

(i) System Parameters: These are of a techno-economic nature, and are set at the beginning of each game session. They reflect the existing situation of the utility for which the planning exercise is to be carried out, and include the following : existing generation capacity by type of prime-mover, load despatch and outage parameters of the various types of power plants, pollutant emission coefficients and other environmental indicators for different types of plants, maximum demand and capacity reserve margin of the system, shape of the load duration curve, tariff rates, and financial position of the electric utility. In addition, the cost and efficiency of generating capacity may also be considered to be system parameters.

(ii) Scenario Variables: These variables provide the setting or the planning environment for the game session. They are often open to discussion, and expert opinion can be successfully incorporated. However, they cannot be changed once the game session starts. These variables, although very important for power planning purposes, are generally beyond the control of the power sector institutions. Important scenario variables are economic growth and oil price paths, demand and price elasticity, technical potential for cogeneration, hydropower and windpower.

(iii) Decision Variables: These represent the decisions made during a game session, and are most crucial from a gaming

point of view. Some of the important decision variables are type and size of generating capacity to be installed in the next planning period, efforts towards reduction in T&D losses, conservation measures to be implemented and so forth.

In the following sections, the various modules are described. It may be mentioned here that these modules are interlinked with each other through various direct and indirect ways, and have been designed to represent reality as closely as possible.

4. Demand Module

This module facilitates the computation of the system maximum demand and system load duration curve (LDC). As a first step, the user is required to specify the number of sectors and their names such as domestic, industry, agriculture etc. The module provides facility to opt for a maximum of four sectors. Further user inputs and computations depend on whether only one sector is specified (i.e. the entire system is represented as one sector) or there are more than one sectors.

In case the user opts for more than one sector, the reference LDCs for each sector need to be entered along with their price elasticities, tariff rates, and annual growth rates. In order to derive the system LDC from the sectoral LDCs, it is very important to take into consideration coincidence factors. Coincidence factors are defined in a 3 by 3 matrix where the fraction of time that sectoral peak time coincides with the system

peak, system intermediate and system base load times are entered in one row. Similarly, the other two rows of the matrix define the degree of coincidence of the sectoral intermediate and base load times with the system peak, system intermediate and system base load times. For analytical purposes, the sectoral peak time duration is given by the time when the demand exceeds 80% of the sectoral peak demand (MW), the sectoral base time duration is given by the time the sectoral demand is less than 20% of its peak demand (MW), and the remaining (between 20% and 80% of the sectoral peak demand) is the sectoral intermediate demand. Likewise, for the system peak, intermediate and base load time durations. The user is therefore required to input the coincidence matrix for each of the sectors specified by him. However, in case this information is not available, the user can proceed on the basis of the default values of the coincidence matrix.

If only one sector is opted for by the user, the reference system peak demand, the population, per capita GDP and GDP elasticity profiles for the planning time horizon need to be entered, from which the system peak demand for future years is computed. In this case, the shape of the system LDC remains the same in future time periods.

The system peak and LDC thus obtained are as seen at the generation bus bar or at the system control center. These however, may be affected by various factors, which include the tariff rates, successful implementation of conservation measures

and decentralized power generation at the consumers' end, reduction in T&D losses and prevailing shortages. It is therefore important to take into consideration the magnitude of influence of these factors on the demand for electricity. The demand module is thus linked with the utility generation module, the tariff module and the conservation/decentralized capacity generation module. The generation expansion plan affects the system peak demand also via shortages, which is also considered in the simulation process. In the multi-sectoral situation, these factors influence sectoral LDCs, which in turn affect the system LDC.

4.1 Data Inputs For Demand Module:

(a) Situation 1: One Sector

- (i) LDC and system peak demand in reference period.
- (ii) Population in time period 't'.
- (iii) GDP per capita in the time period 't'.
- (iv) GDP Elasticity.

(b) Situation 2: More Than One Sector

- (i) Sectoral LDCs and sectoral peak demands in reference period.
- (ii) Sectoral growth rates.
- (iii) Coincidence matrix for each sector.

5. Tariffs Module

This module facilitates the calculation of average tariffs and revenue realised from different consumer categories/sectors as specified by the user. The user is required to input energy

charges, demand rates and the price elasticities for all sectors. The LDC derived in the Demand Module is used as an input here. The user is also required to specify the number of months in a year that a particular sector may be said to have demand in the annual sectoral LDC peak range. This is particularly important for sectors for which a demand charge is levied. As the demand charge is usually on the maximum demand during a 1-month period, it is important to derive some indicators on how much revenue would be realized each month owing to demand charge considerations. For analytical purposes, it is assumed that in the remaining months, the maximum demand will be in the sectoral intermediate load range. These parameters as specified by the user are used to calculate the revenue generated from different consumer categories and average electricity tariff in respective sectors.

The user is free to play around with the input parameters (for eg. he can change the demand rate and/or energy rate for any sector), and can see the impact on the revenue realization and average tariff.

Price elasticity of demand may be defined as the ratio of per cent change in electricity energy requirement to a one per cent change in the price. Given the price elasticity, increase in the demand rate and/or energy rate will result in reduction in the demand and consequently a downward shift in the LDC. The LDC so derived (as a consequence of price changes and price elasticities) is once again used to calculate average tariffs, which in turn

results in a change in the LDC. This process is repeated until the difference between the LDCs obtained from two successive iterations is negligible. The revenue figures computed in this module are used as input for the Financial Module.

5.1 Data Inputs for Tariff Module

(i) Energy rates.

(ii) Demand charges.

(iii) Price elasticity of demand (the user should specify a negative number for elasticity).

(iv) Number of months in a year, a particular sector may be said to have demand in the LDC peak range.

6. Generation Expansion Options

Based on the system peak and system LDC derived in the demand module (section 4), the generation capacity expansion options are analyzed. In fact, it may very well be that the entire demand cannot be satisfied by adding to utility capacity -- or even when decentralized capacity in added and conservation measures in each of the sectors are implemented -- in which case, power shortages emerge. To the extent there are power shortages, the system demand is adjusted downwards; and this adjusted system LDC and system peak demand are then used for projecting demands for future time periods.

As far as utility capacity is concerned, the alternatives considered are coal based power stations, gas turbines, storage hydro, R-O-R hydro and nuclear. The user can set the standard

unit capacities of each type of power plant, and then input the number of units for which construction should begin for each type of power plant. These plants however, will come on-stream after the construction time (again, as specified by the user) elapses. Likewise for decentralized capacity (solar, wind and cogeneration). For gaming purposes, conservation options are considered in the same way as decentralized capacity -- and the user sees the same effects of investing in conservation options as for additions to decentralized capacity i.e. a downward adjustment of the demand. However, conservation options are not pre-set but are included in the simulation process, for each sector specified by the user in the demand module. For each sector however, only one type of conservation measure is considered.

The economic and technical life times of the power plants are specified, and power plants are retired at the end of their technical lifetimes. Likewise, the availability factors of various types of power plant are pre-specified, and determine the extent of energy generation that can be achieved.

As far as the decentralized generation options are concerned, what the user specifies are not the capacity additions of solar, wind and co-generation plants, but rather the contribution of such capacity towards reducing the system peak demand.

Any investment by the utility for capacity expansion is passed on to the Financial Module. Similarly, the environmental effects are also passed to the Environment Module.

6.1 Data Inputs for Generation Expansion Module

(i) Type of generating capacity.

(ii) Size (MW) of one unit of each type.

(iii) Number of units of each type of generating capacity ordered in each time period.

(iv) Life time, construction time, availability factor and other performance parameters of each type of generating capacity.

7. Fuel Use Module

A variety of fuels that are used for generating electricity are considered. These are coal, oil, gas, and natural uranium. Four grades of each fuel types (coal, oil, gas, uranium) are considered in the simulation process. At the beginning of the gaming session, the user can specify the price path for a certain quality (reference grade) of coal, oil, gas and natural uranium. At each time period, the price ratio of the various grades of a particular fuel can be fixed vis-a-vis the reference grade. Likewise, the user can also specify the relative share of various grades of a fuel that will be used.

For each grade of a fuel, the quality (in terms of sulphur content for oil, ash content for coal etc.) is pre-specified. Therefore, to the extent the different grades are used, the environmental implications will be different. These aspects are considered in the Environment Module. The costs incurred in using the various fuels are passed on to the Financial Module.

7.1 Data Inputs for the Fuel Use Module

(i) Prices of various grades of coal, oil, gas and natural uranium relative to that of the respective reference grades.

(ii) "Market Share" of various grades of coal, oil, gas and natural uranium.

(iii) Calorific contents of the various grades of coal, oil, gas and natural uranium.

(iv) Ash content in various grades of coal, sulphur content in oil, and other parameters of environmental implications.

8. Transmission and Distribution System Module

The transmission and distribution (T&D) system in India normally comprises the EHV/HV, MV and LV systems at voltage levels of 400 kV, 220 kV, 132 kV, 66 kV, 11 kV and 0.4 kV.

Investment in EHV/HV levels is reported to be related more directly to investment in power generating capacity, while investment at the MV and LV levels is more directly related to rise in demand.

The EHV/HV line additions (circuit-km/kW of generating capacity) may therefore be specified directly in the generation options module. Likewise, for each sector, the voltage level at which it is to receive power (MV or LV) may be specified in the Demand Module; while the T&D investment requirement at the LV and MV levels is specified in the T&D module.

At the beginning of the gaming session, the T&D loss levels as experienced by various demand sectors are also specified; along with the investment levels which will be necessary to maintain that level of losses with increases in generation capacity or demand, as applicable.

As the T&D losses do reduce with increase in investment levels, this factor can also be accounted for in the simulation process. The user has only to specify the fraction of additional investment in each sector and voltage level in order to gauge the impact on T&D loss reduction. The relationship between reduction in T&D losses and additional investment is modelled as a hyperbolic function.

As the level of losses depend on the system demand (MW) and sector demand (MW) at any particular time, this aspect is taken into account with a simplifying assumption that: (i) the user has specified annual average T&D losses; and (ii) the losses at any time are proportional to the MW demand at that time. With changes in average loss levels, the sectoral LDCs are thus modified.

8.1 Data Inputs for T&D System Module

(i) Losses at various voltage levels.

(ii) Investment levels (Rs/kW of installed capacity for EHV/HV and Rs/kW demand at LV and MV levels) required to maintain the losses to original levels.

(iii) Additional investment that may be made in order to bring down the losses.

9. Financial Module

As already mentioned, the financial module is linked to the tariffs module, the generation expansion options module, the fuel use module, and the transmission and distribution system module. The tariffs module coupled with the demand forecasts (as arrived at in the demand module), gives the revenues earned by the electric power utility.

From the other modules mentioned above, some idea of the costs or expenditures incurred can be gained. In addition, at the beginning of the first time period, the concerned utility also has outstanding debts, which are considered. These also contribute to the repayment schedule of the utility.

The user is thus in a position to see whether the annual revenues are adequate to cover the likely annual expenses of the utility.

10. Environment Module

The module is not intended to quantify the costs incurred in mitigating the environmental implications of power systems expansion but only to quantify the impacts in physical terms; for instance carbon-dioxide emissions, NOX and SOX emissions, quantum of solid coal waste and nuclear waste etc. The physical quantities of air pollutants and solid wastes serve to inform the user of environmental implications of following certain power system expansion strategies.

Regarding nuclear capacity, solid wastes with both low and high level radiation are quantified. The probability of nuclear accidents is also worked out, with a random number generator. Three types of nuclear accidents are envisaged : (i) a big/major accident, which results in high level radiation, to make the entire state/country where the electric utility serves uninhabitable for several decades -- this also ends the game; (ii) a medium scale accident in one of the reactors, when all the existing power plants are shut down for two time periods for cleaning up and installing additional safety measures, which push up the cost of nuclear power by 25%; and (iii) a small accident in one of the reactors, when all existing nuclear reactors are again shut down for two time periods for cleaning up and for meeting the specifications of other safety regulations, which increase the costs of nuclear power by 10%.

Table 1: Trends in Annual Growth Rate of GNP, Electricity Generation and percentage of Power Shortages

Year	GNP growth rate (% per annum)	Growth rate of electricity generation (% per annual)	Percent Power shortages
1974-75	-	5.2	14.1
1975-76	-	12.9	10.3
1976-77	-	11.5	5.8
1977-78	7.5	3.4	15.5
1978-79	5.6	12.2	10.3
1979-80	-4.9	2.1	16.8
1980-81	7.2	5.9	12.6
1981-82	5.9	10.2	10.8
1982-83	2.6	5.7	9.2
1983-84	8.0	7.6	10.8
1984-85	3.8	12.0	6.7
1985-86	5.0	8.5	7.9
1986-87	3.9	10.3	9.4
1987-88	3.8	7.5	10.9
1988-89	10.6	9.5	7.7**
1989-90	4-4.5*	12.0#	-

* Anticipated.
\# April to December.
** April to February.

Table 2: Plan Outlay for the Power Sector

Period	Allocation for the power sector as a percentage of total plan allocation
Ist Plan (1951-56)	13.3
IInd Plan (1956-61)	10.0
IIIrd Plan (1961-66)	14.6
Annual Plans (1966-69)	18.3
IVth Plan (1969-74)	18.6
Vth Plan (1974-79)	18.8
1979-80	18.4
VIth Plan (1980-85)	16.6
VIIth Plan (1985-90)	19.0

Figure 1:Power Sector Planning Framework

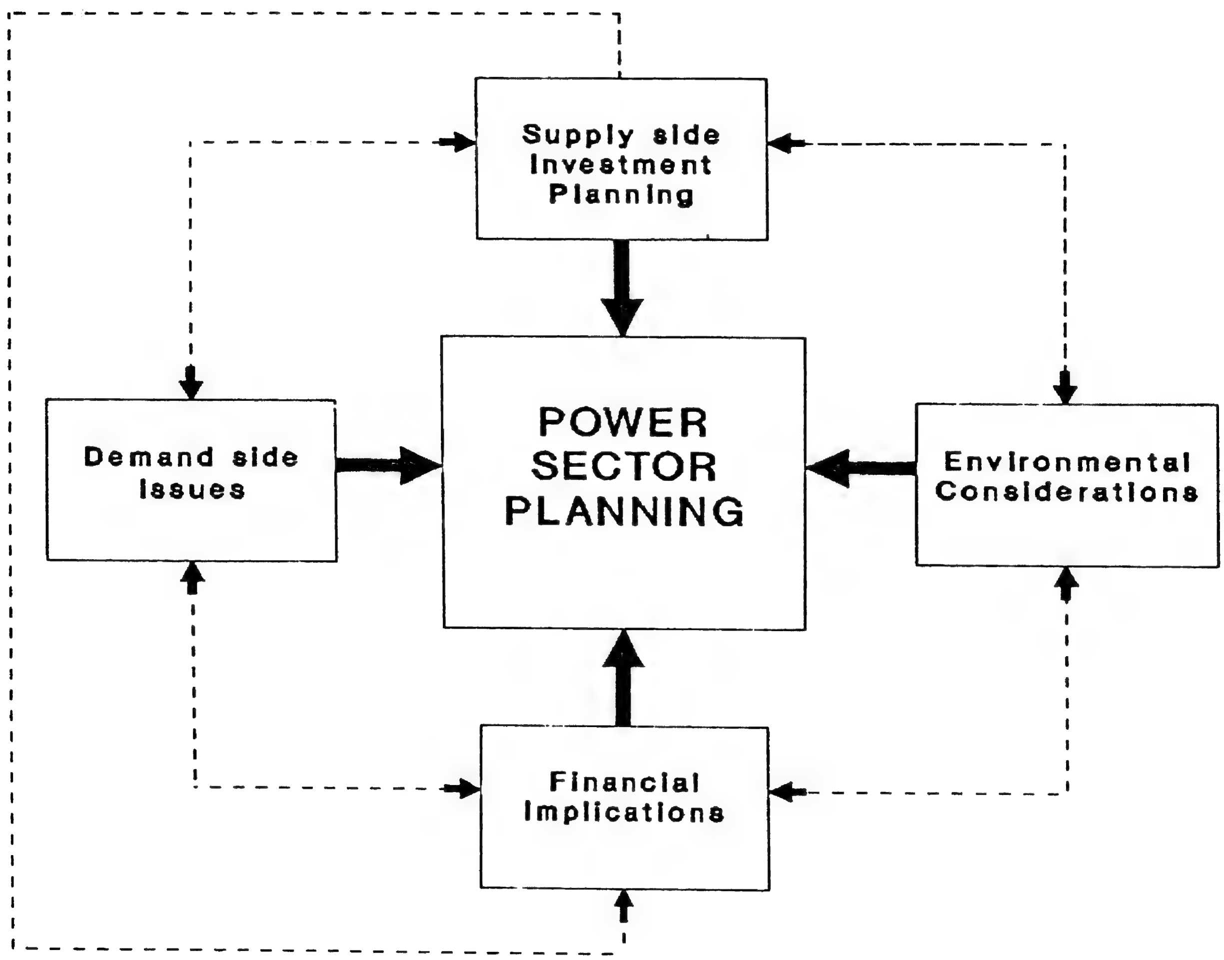


Figure 2(a): Demand Module (one sector)

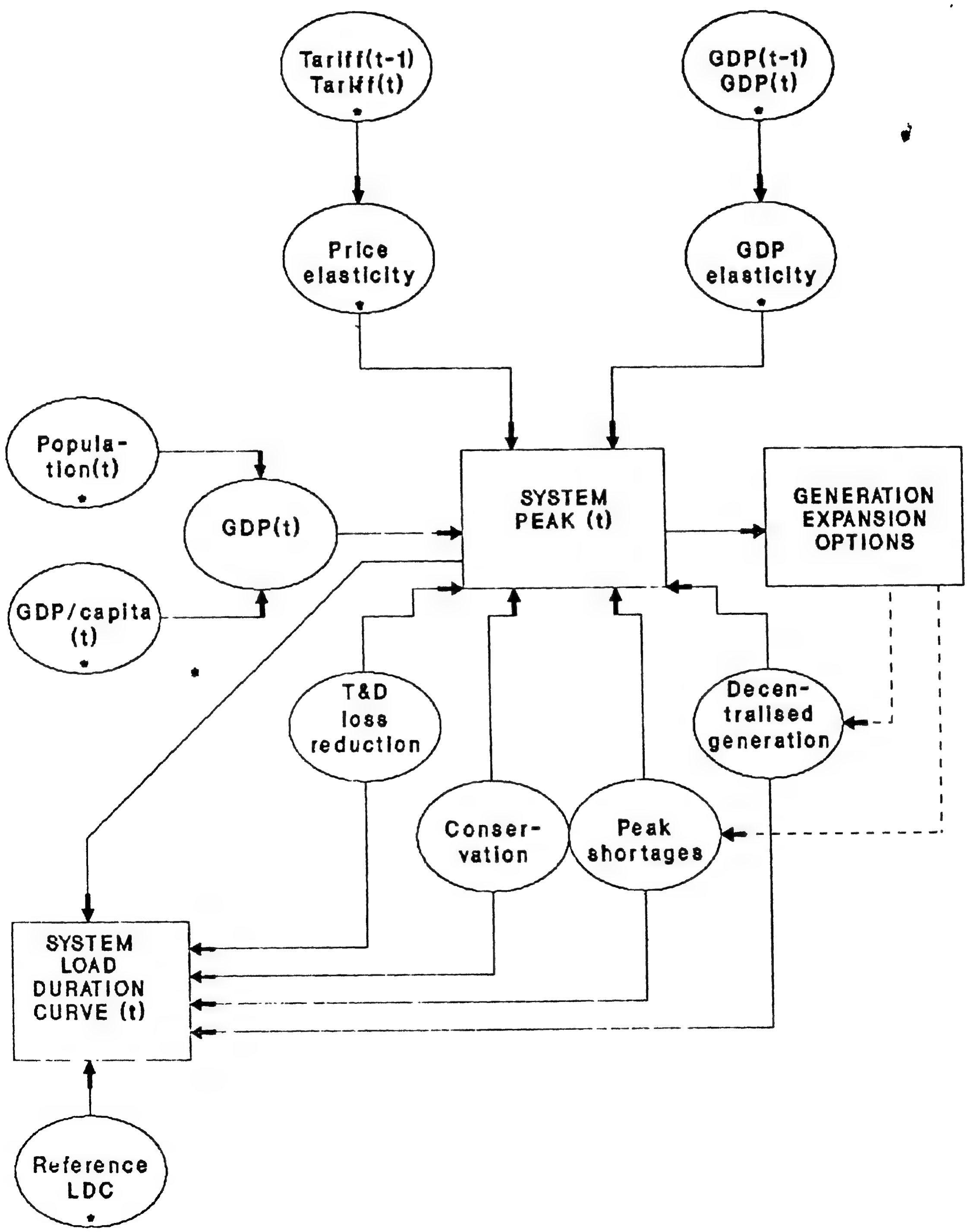


Figure 2(b): Demand Module (multiple sectors)

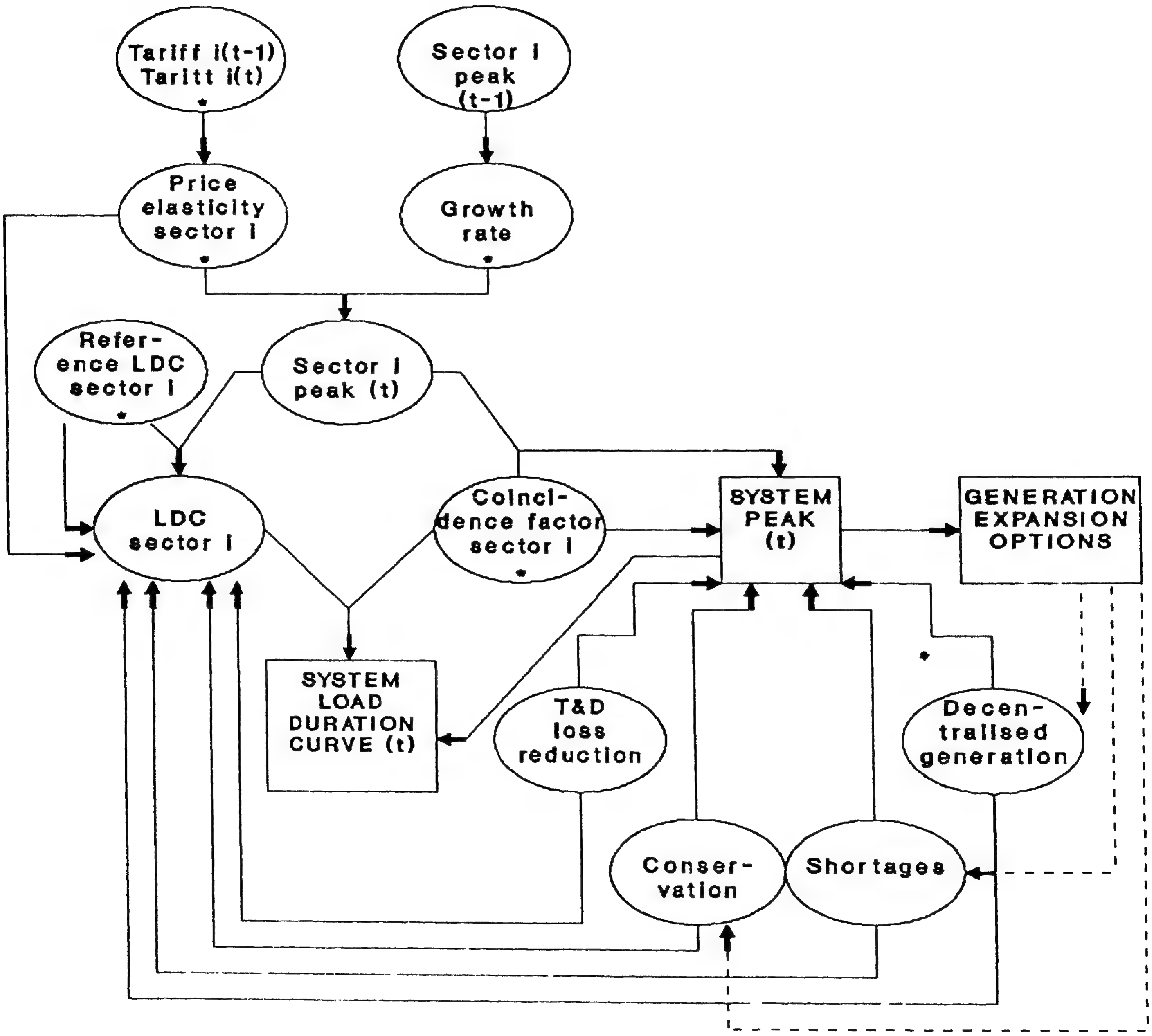


Figure 3: Tariffs Module

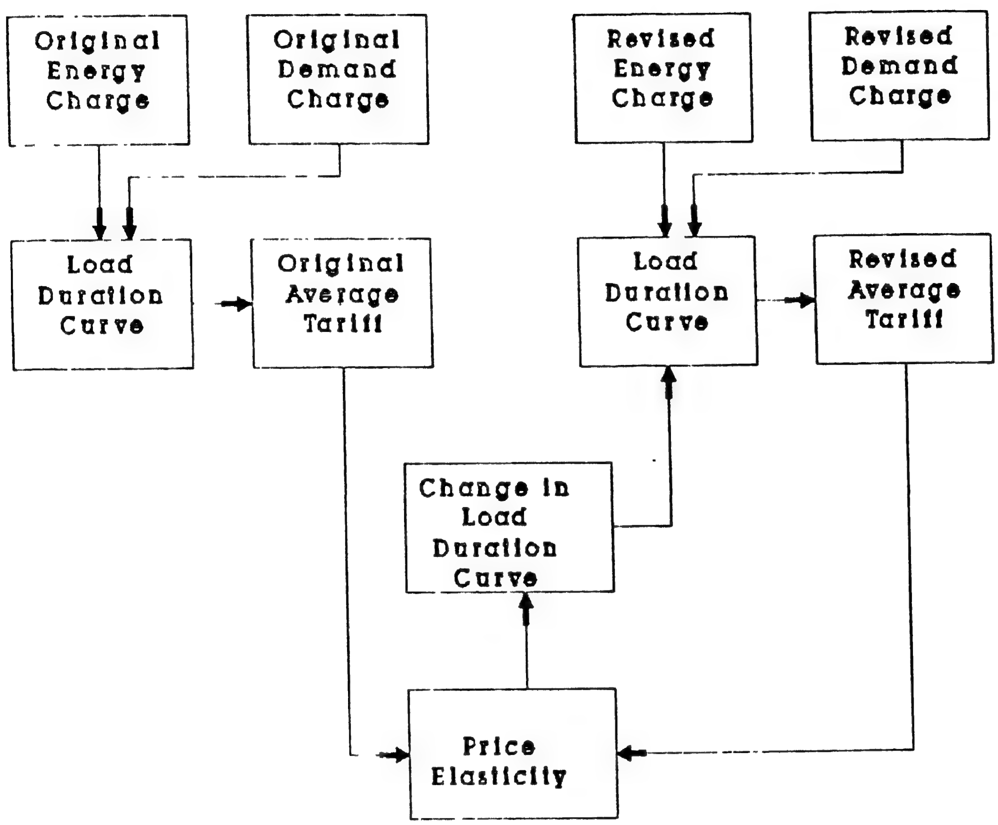


Figure 4: Generation Expansion Options

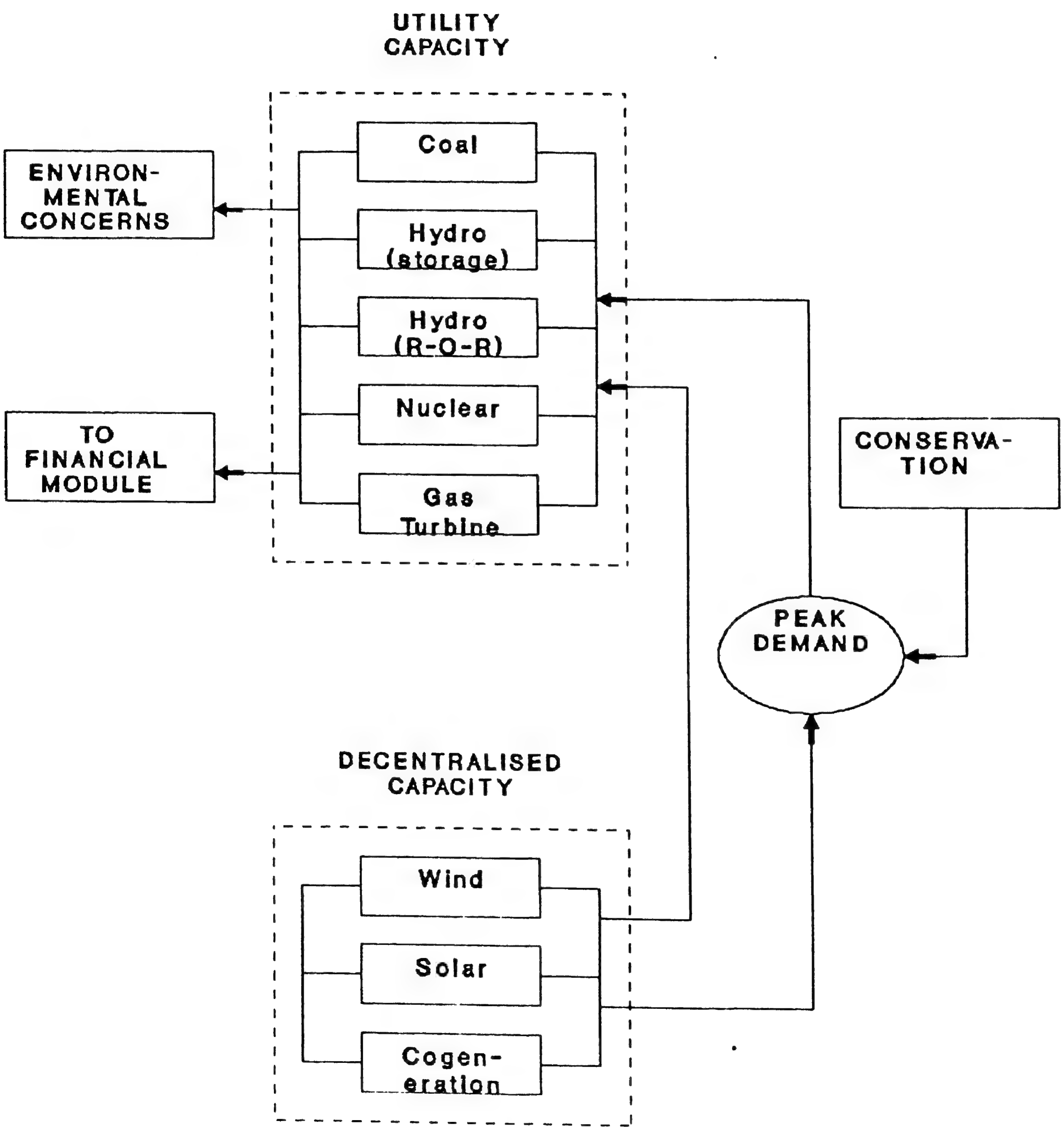


Figure 6: Transmission and Distribution System Module

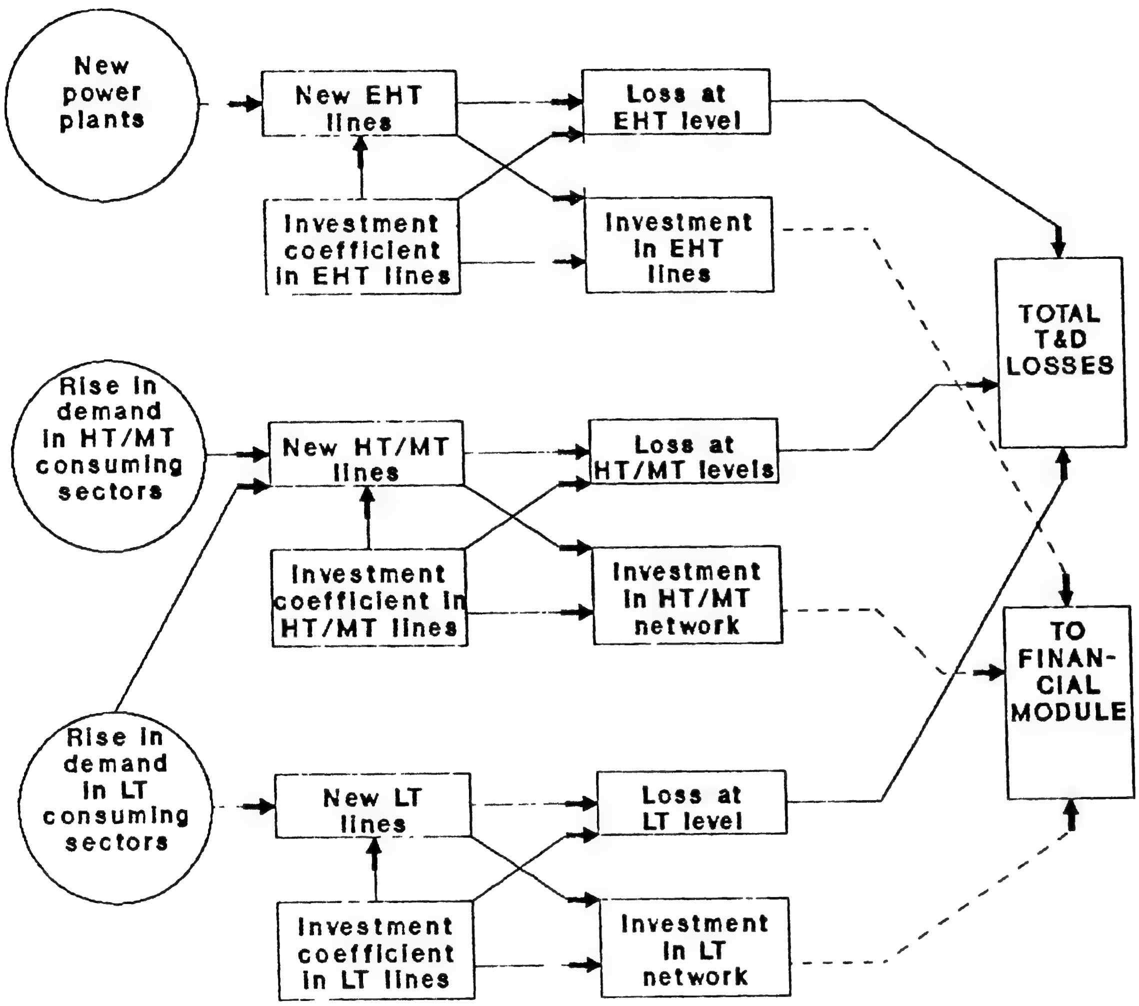


Figure 5: Fuel Use Module

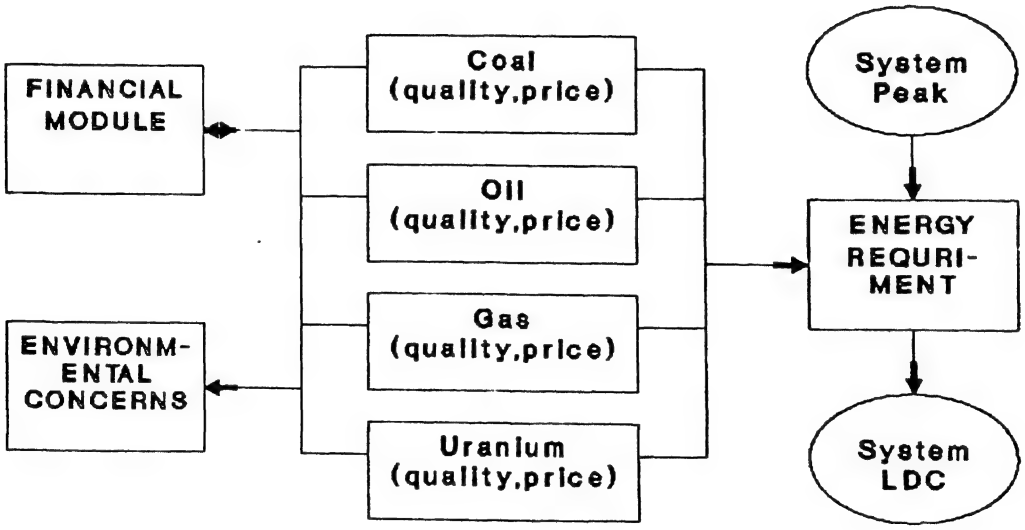


Figure 7: Financial Module

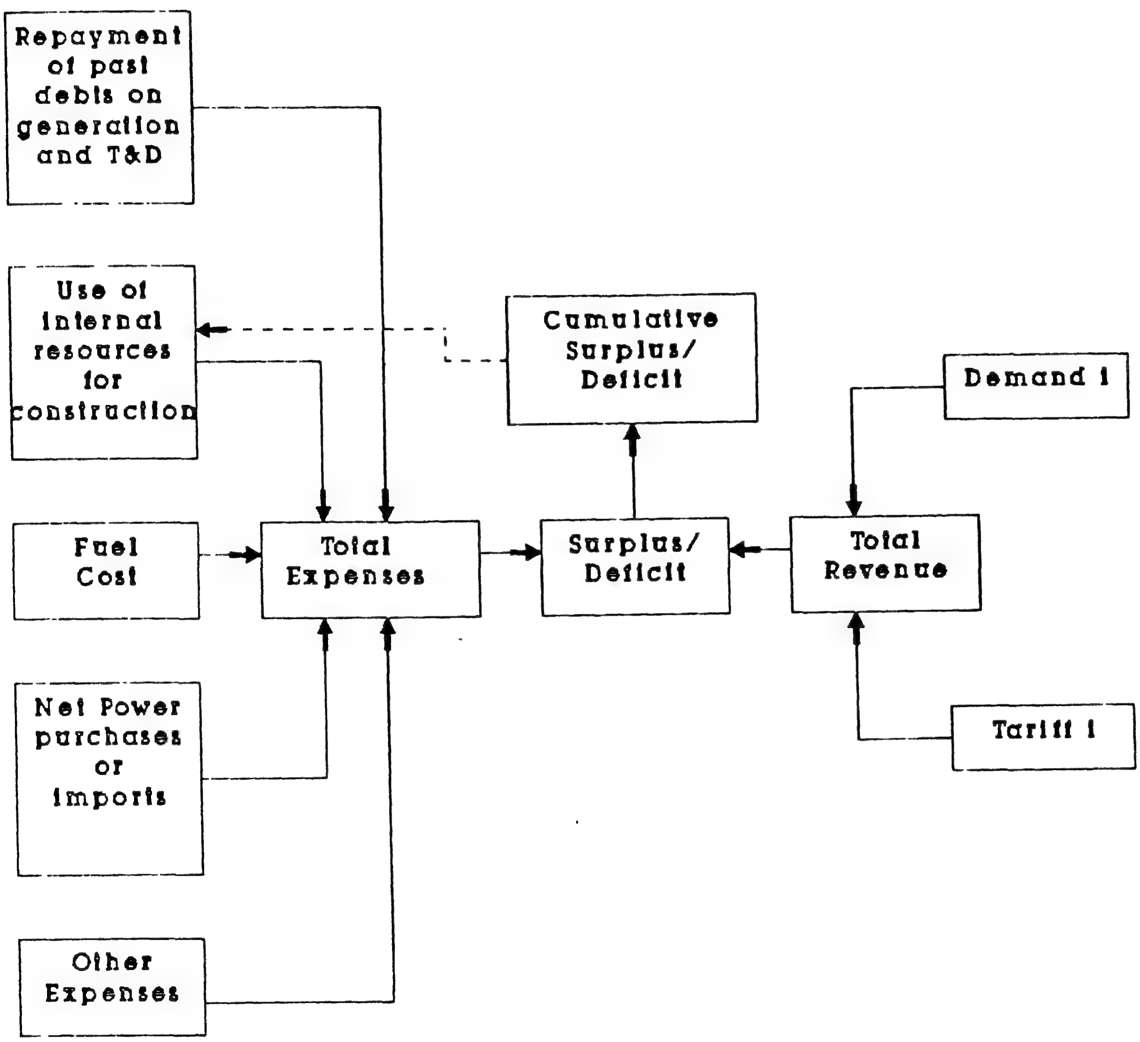
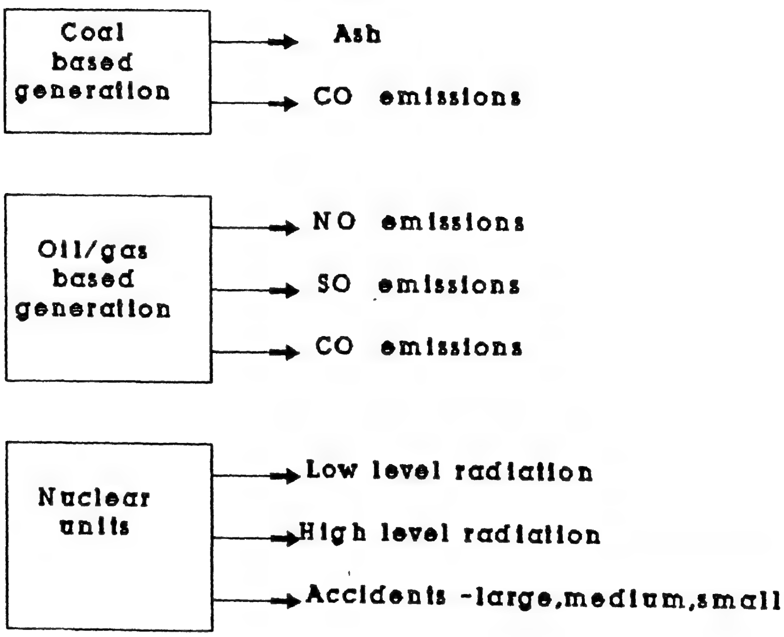


Figure 8: Environmental Concerns



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GRID INTEGRATION OF DANISH WIND TURBINES.

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1. Introduction.

In the recent years, there has been a rapid growth in the number of wind turbines connected to the Danish electricity supply system. As of 1st January 1989, the total number of all grid-connected wind turbines in Denmark was 2.050 units. The total electrical capacity was 190 MW. In 1988, the power production was about 290 GWh, and this corresponds to about 1.0% of the country's electricity consumption. As of 1st January 1988, the total number of grid-connected small-scale wind turbines in Denmark was 1630 units, and the total electrical capacity was 110 MW.

As a by-product of this technological advancement, a valuable collection of experiences has provided insight into many potential problems of linking wind turbines to electric utility systems. In some respects the Danish experience is similar to that of other countries regarding power quality problems, for instance. A more specific Danish problem would appear to be a topic such as how to handle "surplus power", and also one involving load-frequency control at high levels of wind power penetration. Therefore, an extensive study project on power grid integration was undertaken some years ago.

Some of the Danish wind turbines, e.g. the multi-bladed windroses, are not grid-connected. They are mainly used for heating or water pumping. Wind-diesel installations are not in common use, but some initial experimental units have been installed.

2. The Danish Electricity Supply System.

The Danish electricity supply is based almost completely on fossil-fuel thermal steam power stations. Many of these are combined heat and power stations producing heat for urban district heating and electricity for the public grid. The predominant fuel is coal in contrast to the years before the energy crises when it was oil.

Figure 1 shows the location of the various Danish power stations. The map also shows the interconnection lines to Norway, Sweden and West Germany. Through these transmission lines and cables the two Danish power systems are linked to the Norwegian and Swedish systems. There is no electrical connection across the Great Belt.

The Great Belt thus divides the country into two supply areas. In the western area seven power production companies collaborate within the utility association ELSAM. In the eastern area three power production companies collaborate within ELKRAFT Power Company Ltd. A total of 120 electric utilities are responsible for the electricity distribution in Denmark. 54 of these are owned and operated by municipalities, 54 are cooperatives or partnerships, 10 are private foundations and 2 are joint-stock companies.

The integration of the Scandinavian power grid into one interconnected grid is of great value in matching electricity production with demand. Short-term discrepencies between demand and production in Denmark are balanced out by the Norwegian and Swedish hydro power stations because hydro power responds quickly to load variations. Remaining discrepencies between demand and electricity production are corrected from Danish load dispatching centres by ordering the power stations to change their production rate. In this context in must be borne in mind that coal-fired steam power stations are relatively slow acting compared with oil-fired stations.

Table I summarizes the types of publicly owned generating plants in Denmark as of 1st January 1989. Privately owned wind turbines are not included.

Table I. Types of generating plants.

Type	Capacity	%
Steam	7.507 MW	95.6
Gasturbines	245 MW	3.1
Diesel	63 MW	0.8
Hydro	8 MW	0.1
Wind	28 MW	0.4
Total	7.851 MW	100.0

Several types of fuel can be used in the Danish power stations. Thus 79% of the production capacity can be fuelled either by coal or oil, 9% either by natural gas or coal/oil, 11% only by oil and 1% only by coal. (The figures refer to estimated installed capacity). Coal covered 94%, oil 4%, and natural gas the remaining 2% of the fuel used in 1988.

In Denmark heat and power are commonly produced in a combined process. Table II summarizes the key figures for production and consumption of electricity and district heating from power stations in 1988.

Tabel II. Production and Consumption.

Total continous electrical capacity	7.851 MW
Maximum net demand	5.789 MW
Net production of electricity	24.297 GWh
Net import from abroad	5.425 GWh
Purchase from autoproducers	298 GWh
Sales to consumers	27.963 GWh
Production of district heating	52.913 TJ
Total coal, oil and gas consumption	259.300 TJ

The district heating supply from power stations contributes up to about 50% of the total supply of district heating and about 20% of the total heating requirements in Denmark. Purchase from autoproducers by utilities includes about 248 GWh generated by private wind power plants.

According to 1988-prices, the fuel costs for typical conventional power stations were approximately 11 øre per kWh for both coal and heavy fuel oil (12 kr./GJ , 9 GJ/MWh).

Excluding taxation, the average electricity price as of 1st January 1989 for a Danish low-voltage customer consuming 3000 kWh per year was 43 øre per kWh, and the average subscription charge was 392 kr. per installation. The average production costs, respectively distribution costs, were 31.5 and 11.5 øre per kWh.

Note:

All calculations in this paper are performed in Danish kroners = 100 øre. At the time of writing, the exchange rate was: 1 US $ = 7.25 Danish kroners.

3. Accounting Rules for Wind Power Generation.

Thc first accounting rules for sales of electricity from grid-connected wind turbines to local electric utilities were set up in 1976 by the Association of Danish Electic Utilities. As of 1st October 1984 completely new rules with an agreed continuance of ten years came into force. Since then, the agreement has been currently revised, and the rates have also been updated. All prices quoted in this section are valid from January 1989.

According to the latest agreement between the electric utilities and the Danish Wind Power Association, the electric utilities buy wind-generated electricity at rates as specified in the following two cases, also illustrated in Figure 2 (single and joint ownership):

1. The surplus production from wind turbines placed as an internal component of the owner's installation is bought by the electric utility at a rate of 70% of the utility's net selling price to ordinary domestic consumers. (For installations prior to 1986. For later installations, the rules are more complicated).

2. Within a certain limit, all electricity produced by wind turbines connected to the public grid with a separate installation, and with all owners belonging to the same municipality, or living within a distance of 10 km from the wind turbine, is bought by the utility at a rate of 85% of the utility's net selling price to ordinary domestic consumers.

In both cases VAT and a special electricity tax are excluded, and the same applies to the administrative and metering costs (1.9 øre per kWh). With these items left out, the net selling price is 43 - 1.9 = 41.1 øre per kWh taken as an average for all Danish utilities. The buying rate is higher in case 2 than in case 1, because the utility in case 2 receives the revenue of a normal sale of electricity to the wind turbine owners.

The electricity tax is 32.5 øre per kWh on all electricity consumed domestically. Electricity generated by renewable energy sources is exempted from this taxation - whether or not it is temporarily "stored" in the public grid system. The exemption from the electricity tax is administrated by adding the value of the tax to the payment that owners of wind turbines receive for supplying wind-generated electricity to the grid.

Although this is the main principle, the "pay-back rate" of electricity tax is at present restricted to 23 ør per kWh. In both cases the VAT of the electricity tax is also added to the price of wind-generated electricity. (This applies to private installations. For mixed private/commercial installations, the rules are more complicated).

Disregarding the complicated cases, results of the above-mentioned accounting rules are as summarized below, and all prices they are average Danish utility prices.

<u>Purchase</u> (P) from local utility = selling price (production + distribution) + electricity tax + 22% VAT of preceeding items = 43 + 32.5 + (9.5 + 7.2) = <u>92.2 øre per kWh.</u>

<u>Sale</u> (S) to local utility (single ownership) = selling price - administrative costs) x 70% + electricity tax + 22% VAT of electricty tax = (43 - 1.9) x 0.7 + 23 + 5.1 = <u>56.9 øre per kWh.</u>

<u>Sale</u> (S) to local utility (joint ownership) = (selling price - administrative costs) x 85% + electricity tax + 22% VAT of electricity tax = (43 - 1.9) x 0.85 + 23 + 5.1 = <u>63.0 øre per kWh.</u>

Electricity produced by wind turbines owned by electric utilities is not exempted from taxation, neither will electric utilities in the future receive any government subsidy for their installation. The same applies to municipalities. Private owners of wind turbines receive at present time a 10% government installation subsidy, and 35% of the grid-connection costs are reimbursed by the electric utilities with 377 kr per kW as an upper limit.

The government has further recommended that the electric utilites reject grid-connection of private wind turbines in cases where these are not eligible for the government installation subsidy.

4. Grid-Connection of Wind Turbines.

4.1. General Guidelines.

In 1976 the Association of Danish Electric Utilities (DEF) published a set of general guidelines for the connection of

small-scale wind turbines to the utility grid system. The main conditions were as follows:

- Connection of private power-generating equipment must be reported to the local electric utility by an electrical contractor who is authorized to do so by the utility.

- The equipment must be designed in such a way that the wind turbine is automatically disconnected from the grid in cases of malfunctions, either on the utility grid or in the equipment itself.

- Permission to connect a wind turbine to the power grid is granted under the condition that no disturbance in the voltage of the power grid is caused by the equipment.

- A person must be assigned as responsible for the operation of the equipment. An agreement between this operator and the local electric utility must establish rules for the operation of the grid interface equipment.

- Members of the technical staff of the local electric utility may disconnect the power-generating equipment from the utility grid at any time, for instance, when maintenance or repair work on the grid is being carried out.

4.2. Power Quality Standards.

These guidelines have been followed up by more information from the Research Association of Danish Electric Utilities (DEFU), for instance regarding quality of power.

The effect of wind turbines on the distribution system (10 kV and below) depends on the deployment strategy, see Figure 3. Wind farms connected to 10 kV feeder lines or at substations affect the system in another way than small machines dispersed throughout the electric system. The effect may be voltage variations, fluctuations etc.

With few exceptions, Danish wind turbines are equipped with induction generators that are simple and reliable. The generator is connceted to the grid at the synchronous speed when the wind velocity is high enough. It is automatically disconnected when the power meter for some time has indicated that power is being absorbed from the grid.

In the early days, many on-off operations occured, but the present widespread use of dual-generator systems - and now also the introduction of pitch controlled wind turbines - has reduced the number of on-off operations to a more tolerable level. This is among other things done by introducing a hysteresis between the windspeeds at cut-in and cut-out.

When an induction generator is connected directly to the grid a high in-rush current occurs because an induction generator draws a magnetising current 5-8 times maximum continous rating. This may cause intolerable voltage changes. Figure 4 shows the present Danish power quality standard for the low-voltage level. For voltage changes between 10 and 100 changes per hour, the curve is identical with a well-known international power quality standard. For changes between 1 and 10 per hour, there is no international standard so the depicted curve is only a Danish standard.

Good voltage quality can be established in two ways - or in a combination. The first is to use thyristor inter-connection equipment which is capable of limiting the in-rush to the normal level at full power. In fact this equipment is now mandatory on all small-scale wind turbines in Denmark. The other solution is to reinforce the local utility network in order to reduce the system impedance.

In a distribution system with only a small number of dispersed grid-connected units, the influence of these on the 10 kV and low voltage systems can be neglected. If many units are deployed in a given area and connected to the same 10 kV feeder line, for instance sited in a windfarm, they may cause voltage disturbances both on the feeder line and the low voltage mains connected to the line. If the 10 kV voltage

level is increased by more than 1%, it is normally necessary to increase the capacity of the 10 kV line in order to maintain the required voltage quality in the low voltage system. In the same way, the voltage increase in the low voltage mains from a wind turbine to the 10/0.4 kV substation should in general not be more than 2.5% (6 V). Otherwise, a reinforcement of the network would be required.

Wind farms may offset the voltage control system in 60/10 kV substations. This occurs if the voltage control system compensates for the voltage drop in the distribution system by using the current through the 60/10 kV transformer as an indication of the load level. This current measurement is, however, misleading if a wind farm is supplying power to the grid. In this case the output current from the farm should, therefore, be subtracted from the first mentioned current measurement.

The question of reactive power compensation also calls for attention. One way out of the problem is to install a capacitor battery in each wind turbine and to design and operate it in such a way that islanding situations would be of short duration and not accompanied by over-voltages. As a crude rule of thomb, each wind turbine in a wind farm should be provided with a capacitor battery dimensioned to compensate for the reactive power consumption at zero load. In addition, an adjustable capacitor battery can be connected to the common output lines from the windfarm and used for final compensation if the wind farm is connected to a separate feeder line.

4.3. Protection and Safety Requirements.

The main concern for the utilities is to avoid supply of power from a wind turbine to a portion of the system which is disconnected from the main system (islanding). This could lead to both personnel and material damage.

To avoid this risk of islanding, a frequency detection relay should disconnect the wind turbine from the grid if the frequency is outside the range of 47-51 Hz for more than 0.2

second. A voltage detection relay should disconnect the wind turbine if the voltage is outside the range of 207-242 volt for more than 1 minute, and within 0.5 second if the voltage exceeds 250 volt. Three phase measurements are presupposed.

If reactive power compensation is used harmfull overvoltages may quickly occur in islanding situations. Supposing 100% compensation at zero load, the capacitor battery should be switched off within 0.2 second if the voltage reaches 250 volt or the frequency is outside the range of 47-51 Hz. The turbine will be disconnected from the grid according to the above mentioned criteria.

As a general rule, automatic reclosing is normally allowed on distribution systems (10 kV lines) with a high percentage of temporary faults. (Automatic reclosing means that the 10 kV line is disconnected from the busbar for about 0.3 second). Danish grid interface equipment is usually designed in such a way that an automatic reclosing event automatically disconnects adjacent wind turbines from the grid due to lack of power supply to the relay system. Until recently, a manual reset action was needed to restart the turbines but today automatic equipment is provided so restart automatically follows after a time delay of approximately 15 minutes.

5. Power Integration Study.

As mentioned above, the existing Danish power generation system is characterized by a high degree of combined heat and power production. This sets limits on the possibilities of stopping co-production units; for instance during night hours in winter when the demand for heat is high while the demand for electricity is low. The amount of wind-generated electricity which cannot be absorbed by the power system, so-called "surplus energy", increases rapidly with the installed wind power capacity.

For this reason a simulation study was carried out in 1983, the aim of which was to identify the problems encountered at high levels of wind power penetration. A computer programme

simulated the operation of the conventional power system supplemented with unpredictable elements of power production from an increasing number of wind turbines. The simulation programme calculated savings in operating costs and fuel expenses as well as the "surplus energy" generated by the wind power plants.

Calculations for the ELSAM-area (Jutland and Funen) at the expected 1987 stage showed that a wind energy contribution of, for example, 10% of the total electricity production would lead to an amount of "surplus energy" close to 15% of the total production of wind-generated electricity. The figures for the ELKRAFT-area (Zealand) were rather similar to these. The situation is anticipated to be more or less the same in 1995.

The simulation study also showed that even at low levels of wind power penetration "surplus energy" is to be anticipated on certain occasions. If this happens, either some wind turbines must be stopped or the electricity must be used for other purposes, for instance electrical heating. This solution presents no technical problems, only economic disadvantages.

Some Danish power stations have heat storage facilities, e.g. large water tanks with hot water to be used for district heating during peak load hours. By increasing the size of these storage facilities the amount of wind-generated "surplus energy" can be reduced. Again, the economy of such a scheme must be considered.

If Denmark had a considerable supply of hydro power from high dams, the problem of energy storage would be easier to solve as the water behind the dams effectively stores energy. The storage problem together with any problem of matching the production with the electricity demand may find its solution by keeping some quick-acting oil-fired power stations running. Alternatively, the present Scandinavian collaboration on electricity supply might be extended to take the existence of Danish wind power plants into account.

At present, a special study project addressing the control problem is in progress. The first step is to undertake a series of measurements of the short-term variations in the output power from wind farms. The aim is to determine to which degree these short-term variations are equalized when added together on the common grid system.

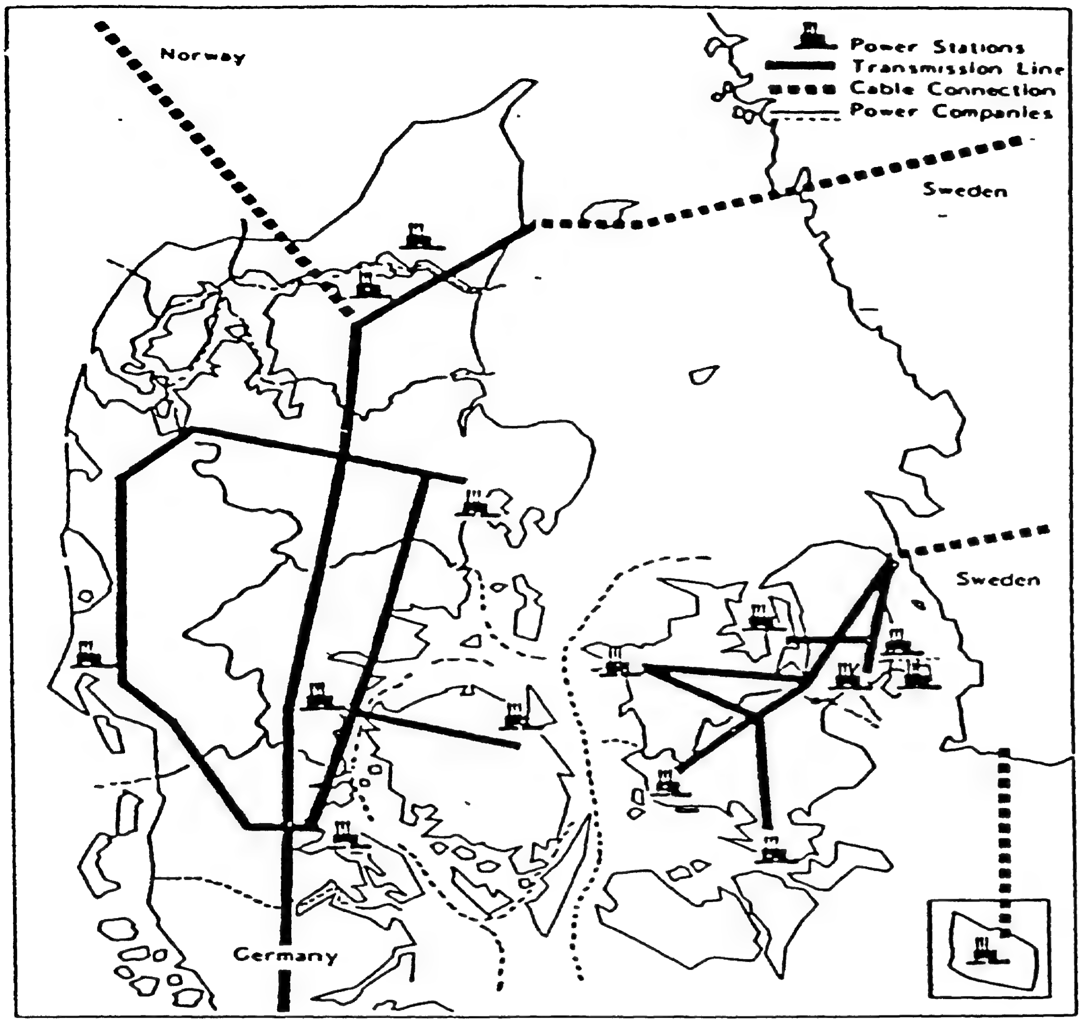
6. Wind-Diesel Project.

The electricity supply system on the small Danish island of Anholt is based exclusively on power from 3 diesel-generator units with an aggregate electrical capacity of 565 kW. Maximum demand in 1985 was close to 400 kW and total annual consumption about 1000 MWh. As of April 1986, the consumer price was 132.5 øre per kWh excluding electricity tax and VAT, and 197.6 øre per kWh including these two items.

A study project carred out in 1986 showed that a wind turbine with a capacity of 45 kW could supply 100 MWh to the grid per year, and thus annually substitute 20.000 l light fuel oil, without affecting the voltage quality on the island provided that proper interconnection equipment was installed.

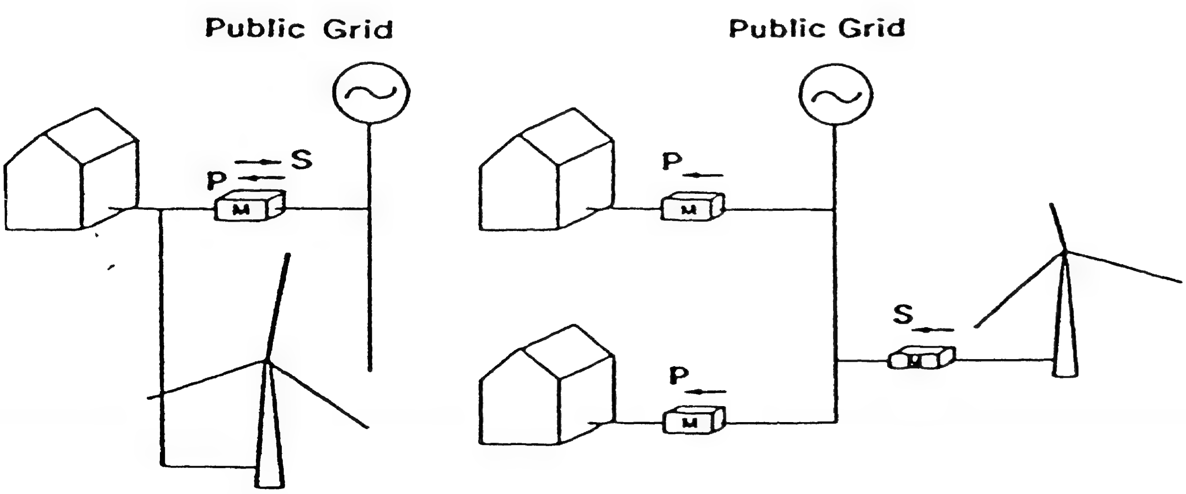
To avoid load-frequency problems, the actual output power from the wind turbine should never exceed about 50% of the total consumer demand. Otherwise, the diesel engines might not be able to control the grid frequency. On certain occasions this condition might have the effect that the wind turbine must be stopped even when wind speed allows it to generate eletricity. Without this restriction the wind turbine could, presumably, produce about 140 MWh per year.

The decision to proceed with the project, e.g. to install a wind turbine and implement an adequate measurement programme, has since 1986 been delayed for several reasons. The wind turbine was, however, installed in the beginning of 1989. The operational experience and the results of the measurements are now awaited.



Danish Electricity Supply System: ELSAM-area left. ELKRAFT-area right.

Fig. 1. Main grid system in Denmark.



P : Purchase from Local Utility.
S : Sale to Local Utility.

Fig. 2. Single and joint ownership

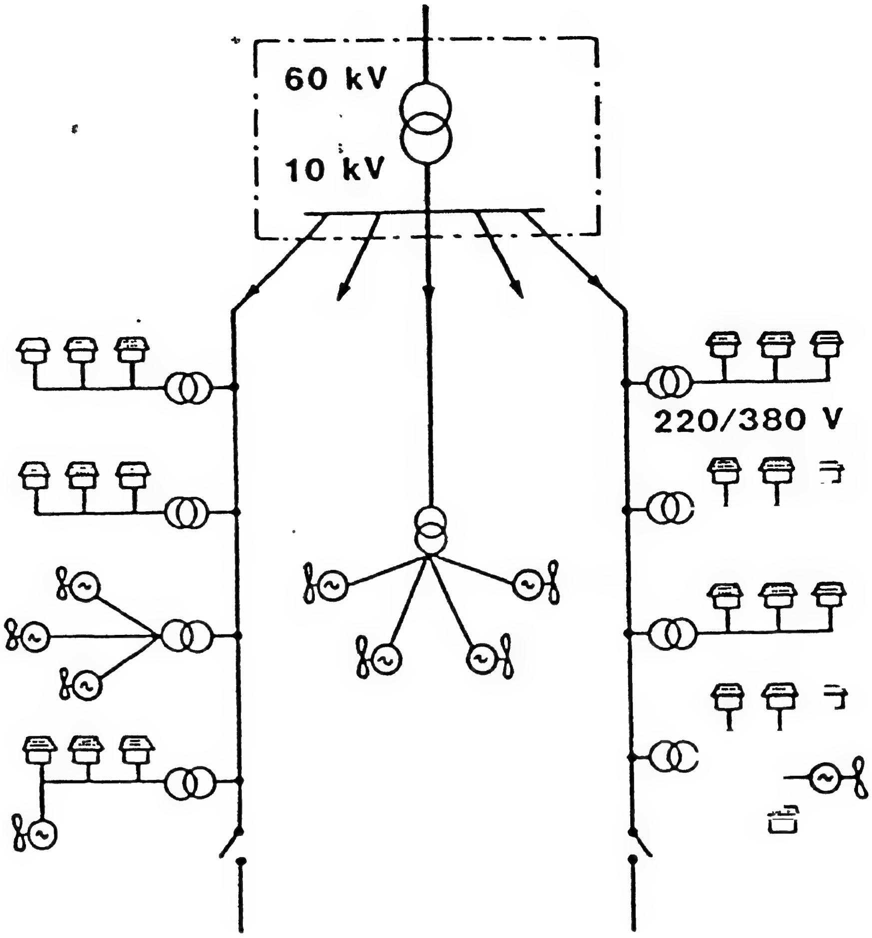


Fig. 3. 60/10 kV substation and distribution system with dispersed units and a wind farm.

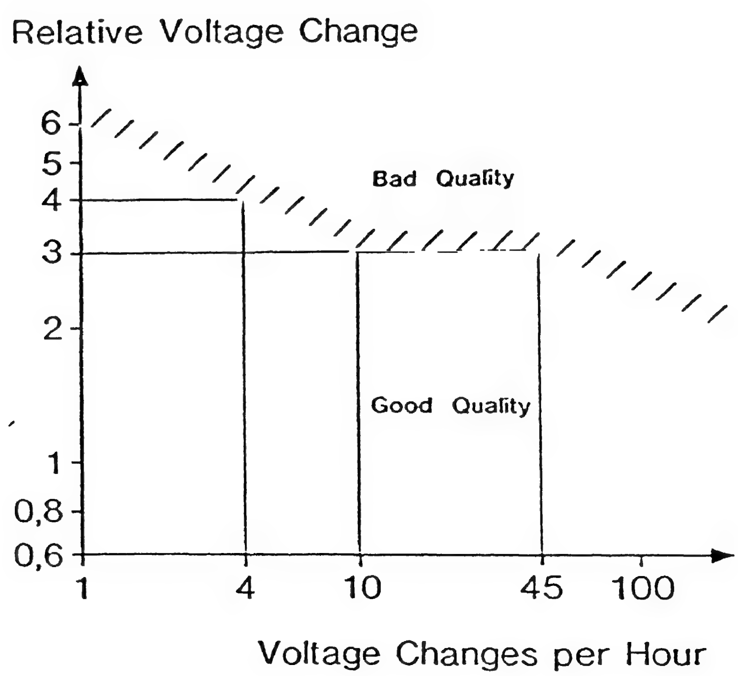


Figure 4. Power quality standard for the low voltage level.

STRATEGIES FOR IMPROVING PERFORMANCE OF EXISTING THERMAL POWER STATION

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POWER SYSTEMS PLANNING AND ENVIRONMENTAL CONCERNS

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1. INTRODUCTION

Environmental concerns due to large scale power generation encompasses the physical, biological, cultural and social environment. Amongst other impacts, fossil fuel based power plants produce significant levels of air pollution, nuclear power plants are associated with radiation hazards and hydro-electric with large scale displacement of people and destruction of the ecosystem.

In the developing world there is a growing need for generating more electricity in a least cost manner. Alongside, there is also a growing awareness for safeguarding the environment. Since both are required for a better quality of life a mutual accommodation or trade off needs to be achieved. Some of the environmental impacts can be mitigated by using economic remedies. For e.g., air emissions can be decreased by various pollution control equipment, with varying costs and levels of effectiveness. In other cases such as in hydro, large scale displacement of people and destruction of the ecosystem can only be reduced by reducing the height of the dam which also results in reduced power availability. This paper presents some of the major environmental concerns associated with fossil-fuel, nuclear and hydro-electric power generation and ways and means of mitigating these concerns, wherever possible.

2. FOSSIL FUEL BASED POWER PLANTS

2.1 Coal Power Plants

Air Pollution: The composition of flue gases when coal is burnt are sulphur oxides (SO_x), Nitrogen oxides (NO_x), Carbon monoxide

(CO), Carbon dioxide (CO_2), particulates (SPM) along with hydrocarbons, radionuclides and aldehydes.

The major sulphur oxide emitted is sulphur dioxide (SO_2). Major impacts include health effects, with increasing incidence of pulmonary, asthametic and respiratory diseases; corrosion effects, especially from sulphuric acid attack; and chronic plant injury promoting excess leaf shedding and reduced productivity. Methods of mitigation are i) use of low sulphur coals, ii) installation of flue gas desulphurisation (FGD) system. FGD systems using wet lime or limestone slurry process produces a solid waste and are also called throwaway systems (no salable by-product). FGD 'regenerative' systems are based on i) magnesia slurry scrubbing or catalytic oxidation, both of which produce sulphuric acid, and ii) sodium solution scrubbing which produces sulphur.

Nitrogen oxides (NO_x) mainly consist of nitric oxide (NO) and Nitrogen dioxide (NO_2). During the combustion process the small amounts of nitrogen present in fossil fuels combines with oxygen and produces NO. This is a relatively non-irritating gas and is therefore believed to pose no health threat at ambient levels. However, NO rapidly oxidises to NO_2, which has a much higher level of toxicity. Both NO and NO_2 are also important in the creation of photochemical oxidants (smog). The major health effects of NO_2 are lung disorders, emphysema and chronic nephritis. Unlike SO_2 that can be absorbed in the fluids in the upper tracheo-bronchial zone, NO_2 is less soluble and thus can penetrate deep into the lungs where tissue damage occurs. Methods of mitigating NO_x emissions are generally based on combustion

modification techniques involving modification of burners and use of low NO_x burners. More advanced techniques involve flue gas denitrification using chemical process.

SO_x and NO_x in random also produce acid rain which has an effect on materials and the ecological system.

Particulate emissions affect human beings by way of aggravating asthama, emphysema, cardiovascular disorders, cough and chest discomfort. Control techniques are well established. Fly ash is controlled by Electrostatic-precipitators (ESP) which can separate particles greater than 0.1 micron m. ESPs can separate out 99% of the mass concentration but in term of actual number of particles only 5% are removed. A suggestion is to separate the flue into two streams and to charge each stream oppositely. This would lead to the formation of particles of a large size and hence a greater number (> 5%) would be absorbed by the precipitator. Other collection methods include bag house collectors and fabric filters.

As regards radionuclides, they are inherent in the coal and their removal is difficult. They are mutagenic and carcinogenic.

Aldehydes can be reduced by efficient and complete combustion. Depending on the emission and the metal involved they affect the lungs.

Complete and efficient combustion can reduce the quantum of hydrocarbons produced. These pollutants cause watering of the eyes, coughing, headache, sneezing, backache and nervous weakness. They are also carcinogenic.

Environmental control costs are generally dominated by SO_2 control equipment. Capital costs for FGD (wet lime or limestone

systems) are generally reported to be anywhere between 11% and 18% of total power plant cost with an average of 13% (data from U.S.A., Japan and Germany). Operating costs range from 8% to 18% of total plant costs depending upon the extent of SO_2 removal. ESP costs are about one-third the average investment of FGD. Annual revenue requirements also range from 10 to 30% of the requirements for FGD. Overall particulate removal contributes approximately 2% of total generating costs.

NO_x control costs depend upon whether combustion modification or flue gas treatment is adopted. For the former capital costs are less than 1% of total plant costs. Annual operating costs on an average amount to less than 0.5% of total plant operating costs. Flue gas treatment or denitrification are more expensive. In Japan where both systems have been used the capital requirements are approximately 3% of total plant costs and operating cost being approximately 6% of the annual plant operating costs.

Based on the above a stringent environmental programme can result in upto ~~36~~ 27% of total capital costs and ~~32~~ 30% of annual revenue requirements. The above discussion on costs has been based on a description by Codoni et al (1985). However, the range of costs would be very different from country to country for e.g. China with high sulphur coal will have higher costs than say India which has low sulphur coal. On the other hand even if a stringent environmental programme is not pursued society will be paying a heavier cost, although indirectly, in terms of health damages.

Water Pollution: The major water pollutant produced is heat. During plant operation, steam leaving the final turbine is cooled and condensed to be returned to the boiler. The condenser cooling water systems must be able to remove large quantities of heat from this steam. The elevation in water temperature due to waste heat removal is termed thermal pollution. This affects the aquatic system in the following ways. For some fish species, warmer water spells disaster in the form of increased mortality rates and increased susceptibility to disease. For some other species, warmer water implies a higher metabolic rate which leads to shorter maturing periods and shorter reproduction cycles. This has implication on the food system as it requires an increased production of food to sustain this growth. It also results in increased carbon dioxide production and as warmer water has a decreased ability to absorb carbon dioxide it further increases the levels of carbon dioxide in the atmosphere.

Cooling water systems may be either once-through or recirculating. In once-through systems cooling water is drawn from a source at one location and returned to the source at another location. Thermal pollution here is fairly significant. In recirculating systems the cooling water passes through the condenser several times. After each pass, the water is sent to a spray pond, canal, or cooling tower where heat is removed through evaporative cooling. Discharge to the main source may occur only during blowdown when a blowdown stream is withdrawn and replaced by better quality make up water. Typical blowdown rates are between 0.5 and 3% of total cooling water.

One more outcome of the use of cooling towers that needs to be mentioned is the enormous amount of waste heat that is released. This causes a local increase in temperature and humidity.

Land-use: One of the major problems with coal fired power plants are the large quantities of fly ash and bottom ash that must be handled within the plant and removed to treatment and disposal facilities. Both of these are generally disposed in settling ponds and landfills. Bottom ash settles well and has low solubility. Fly ash, on the other hand settles poorly but adequately if given enough time. The settling ponds can be dredged, with the ash removed to a landfill for final disposal or filled and used as a final disposal site itself. Ponding and landfill occur at the expense of land used for these purposes. Attempts are being encouraged for alternative uses of fly ash in making bricks, cement and in road construction.

2.2 Oil-fired Power Plants:

Air pollution aspects are similar to those of coal-fired plants with a lesser degree of fly ash. Water pollution problems are similar. Solid waste is significantly reduced as there is no bottom ash.

2.3 Gas-fired Power Plants:

The only significant pollutant is NO_x. Water pollution problems are similar to the others described above. There is no solid waste.

3. NUCLEAR POWER PLANTS

Nuclear power plants are perhaps the most complex technology for power generation to evaluate in terms of costs and safety aspects. Costs are difficult to evaluate because decommissioning of nuclear plants have yet to be encountered on any significant scale and estimates of it indicate it to be fairly large. Safety aspects centre around the possibility of an accident with major consequences and although nuclear plants are designed to prevent such an occurrence, there is a chance that such a situation could occur. This aspect is extremely difficult to evaluate and decision-making regarding such-like projects depends upon how society views a situation which has a low probability of occurence but with major potential consequences.

The environmental concerns of nuclear power plants can be described in two categories: i) radiological and ii) non-radiological.

Radiological concerns: The operation of nuclear power plants gives rise to a wide variety of fission and activation products. Significant air-borne effluents include Krypton and zenon (noble gases), tritium, carbon-14, iodine-131 and particulates. Significant liquid effluents include Caesium-137, Cobalt-60, Strontium-89 and 90, Ruthenium-103 and 106, and again Iodine-131 and tritium. Nuclear reactors also produce a large amount of solid waste.

Nuclear power plants are so designed that the occupational workers as well as the general population receive radiation doses far below safety levels. In a perfect reactor system the only

radioactive material leaving the plant would be the spent fuel assemblies. In a real plant, however, with rotating systems, pumps, etc. there is a finite leakage of radioactive effluents into the plant environment. Plant systems, therefore, take this into account and are designed to collect and concentrate radioactive contaminants to facilitate their safe disposal and to purify the air and water that can be discharged to the surroundings. In general the concentration of radioisotopes in effluents are reduced to less than 1% of the maximum permissible concentrations for most radioisotopes; the aim being to keep the radiological risk to as low as reasonably achievable (ALARA). However, a pressing environmental concern is the possibility of accidental releases of radionuclides to reactor accidents results of which would be catastrophic to man and the environment. Depending upon dose levels, exposure to radiation can have somatic as well as genetic effects, consequences of the latter could last over subsequent generations.

Another major concern is the management and final disposal of radioactive waste. As mentioned earlier radioactive gases are formed during the operation of a nuclear reactor. These gaseous wastes are usually released from stacks after various forms of treatment, such as filtration and delay systems to allow the short-lived radioactivities to decay.

Liquid wastes are treated in two ways. When the amount of contained radioactivity is low they are blended with the condenser water discharge. Alternatively they are purified by ion exchange, or on occasion concentrated by evaporation. The concentrate is then converted to a solid by incorporation in cement.

Solid wastes, if combustible are put through a special type of incinerator to achieve large volume reduction. In some cases they are mechanically compacted. They are then stored in underground tanks for short term storage. Long term storage options still need to be worked out. Options include salt mines, ocean beds, etc.

A third important concern is the decommissioning of the nuclear plant at the end of its useful life. Initially the plant would need to be mothballed and kept idle during which the short-lived radioactivity will decay thus permitting the task of dismantling. Unfortunately the timing of actual plant dismantlement is impossible to forecast due to uncertainties regarding health hazards to work force. The dismantled equipment would then need to be sent to waste disposal sites.

Apart from the difficulties that will be encountered in the process of decommissioning another significant aspect is its economic dimension. In fact it has been suggested that the cost of nuclear power programmes have been significantly understated as they do not adequately account for decommissioning (Codoni et al, 1985).

Non-radiological factors: These are centered around thermal water pollution and land use. Thermal water pollution has already been described in the case of fossil fuels. For nuclear plants its to a larger degree. Land requirements are typically 120-240 hectares for a 200 MW plant.

4. HYDROELECTRIC POWER PROJECTS

Here again it is a difficult task to evaluate the concerns both

from a social as well as an economic view point. Hydroelectric power projects centre around the construction of a dam that impounds large quantities of water in man-made lakes. Often the area submerged is fairly large, thus a number of villages, towns, forests, etc. are inundated. This often results in hardship on the people displaced along with the destruction of forest cover with loss of flora and fauna and in many cases a reduction in biodiversity. Here probably the only way to mitigate these impacts is to reduce the height of the dam which would decrease the area submerged and therefore decrease, both, the number of people affected and loss of biological diversity. On the other hand this would also reduce the electricity generation and decrease the irrigation potential. In a sense, these impacts go beyond the economic domain, and are very difficult to assess and quantify. The discussion below elaborates some of the major concerns that are associated with hydroelectric power projects.

The environmental consequences of hydroelectric power projects encompass a wide area that includes the physio-chemical, biological and social environment. The major concerns are:

1. **Displacement and Resettlement:** The number of people displaced due to submergence has been known to run in multiples of ten thousand to over hundred thousand in some cases. These people have to be resettled in new areas. Not only land and cash compensation is required but also in many cases they have to be retrained in new skills since they cannot pursue their old way of life. Often there are social problems associated with the move as people in the resettlement areas do not accept the displaced

people. In the case of Pong dam in India which is located in the foothills of the Himalayas in the Kangra district of Himachal Pradesh, the oustees were resettled in the vicinity of the Rajasthan Canal Project area. The new location was not only climatically drastically different but also culturally in terms of language, customs, food, etc. This brings a tremendous hardship on the people displaced. Thus displacement and consequently the rehabilitation of the people concerned can have drastic social as well as economic dimensions.

2. **Loss of Forests:** In addition to drowning villages and towns reservoirs also submerge vast areas of forests. A particular tragic aspect of forest destruction has been the loss of genetic resources as some of the submerged forests have known to have supported a rich variety of plant and animal life. In many cases the biological diversity has been drastically reduced.

3. **Sedimentation of Reservoirs:** Failure to protect the ecology of the dam's catchment area, and in particular to prevent its deforestation, can lead to severe erosion problems and consequently to the rapid silting up of the reservoirs. This can significantly reduce the reservoir life. The Bhakra-Nangal dam (a large dam in North India), for example, may loose its entire storage capacity within forty years.

4. **Water Borne Diseases:** Large water development schemes invariably favour the spread of various water borne diseases. There could be increases in malaria and other mosquito-borne diseases if proper drainage and water management systems are not

implemented. Studies have also shown that the construction of large reservoirs can result in the elevation of sub-soil water in the vicinity with consequent changes in the levels of fluoride, calcium, trace metals, etc., in soil sediments which in turn results in the emergence of diseases such as fluorosis.

5. **Water Loss and Changes in Water Chemistry:** The increased surface area, surface temperature and wind speeds in reservoirs increase evaporation losses as compared to the original river system. Moreover, losses due to evapotranspiration by water weeds can be enormous. The increase in water loss leads to an increase of dissolved solids. These will favour denser aquatic growth. Uncontrolled weed growth leads to deterioration of water quality. The use of water for irrigation worsens this problem since there are large increases in salinity and hardness in return flows of irrigation water.

6. **Waterlogging and Salinity:** Surface water irrigation by canals have often resulted in water logging and increased salinity. The water seeps out into the subsoil thus raising the saline groundwater to the level of the root-zone of crops, resulting in root damage and a reduction in crop yields.

7. **Dam Safety:** This is a complex task to evaluate, however dams have failed in various parts of the world over the years, resulting in deaths injuries and destruction to property. Filling of deep reservoir behind dams produces an enormous local increase in the mass supported by the earth's surface and this may be enough to trigger an earthquake that could result in a dam

collapse. However this is a difficult feature to evaluate. The situation, again, like in the nuclear case, can best be described as one of 'low probability of occurence but with major potential consequences'.

Note: Information for this paper has been largely drawn from material reported in TERI (1990). Recommended background reading include El Hinnawi (1980), Eicholz (1976), International Energy Agency (1989), Goldsmith and Hildyard (1986) and Noll and Davis (1976).

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Environmental Impact of Thermal Power Generation : A Modelling Approach

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Environmental impact of thermal power generation : a modelling approach

Abstract

This paper presents major environmental concerns associated with thermal power generation and the ways and means of mitigating these concerns. In arriving at a pollution control strategy, ground level concentrations (GLCs) serve as an important indicator. An air quality model was earlier developed by us to predict the GLCs. A brief description of this model type and an overview of the results obtained from it for a typical large power plant is presented.

Introduction

The production, conversion and use of energy in different forms have important environmental implications. These implications can be particularly acute in areas of concentrated population and activity such as large metropolitan cities. Thermal power stations are invariably large size installations that can generate adverse environmental impacts on land, water, atmosphere, etc. In a developing country like India, there is a growing need for generating more electricity in a least cost manner. The total installed generation capacity in the country by the terminal year of Eight Plan shall be 1,02,269 MW. The capacity addition planned during this period (1990-95) is 38,250 MW and the contribution of thermal to this power programme is planned to be about 30,150 MW (78.8%). There is also a growing awareness for safeguarding the environment. Much attention is being paid both by the power generating companies and pollution control boards to mitigate the environmental effects of power generation.

The main pollutants that are released into the atmosphere by the power plants are particulate matter and oxides of sulphur and nitrogen. These emissions are one of the major factors underlying public concern that have lead to the siting of such plants. Substantial R&D programmes are being implemented to either reduce or control the air pollutants. The Central Pollution Control Board in India has formulated an Environmental Act -1986 which gives the emission standards for thermal power stations in addition to the standards for other industries. It calls for particulate retention system to limit the particulate matter emissions. For keeping oxides of sulphur (SO_x) and oxides of nitrogen (NO_x) emissions levels within the limits prescribed in the ambient air quality standards, it warrants a minimum stack height. But the ambient ground level concentrations of pollutants not only depend on rate of emissions or the stack height but also on the meteorological parameters such as wind speed and stability conditions. Also the efficiency of dispersion, or the avoidance of plume droop depends not only on the height of the stack but also on the temperature and velocity at which flue gas is released to the atmosphere. So instead of fixing the minimum stack height, the acceptable ground level concentration has to be taken under control, which can help reduce the capital investment by providing a lower stack height.

To estimate the ground level concentration of pollutants around the power plant, air quality models have to be developed which can simulate the atmospheric dispersion and predict the concentration levels. Thus, by simulating the different conditions of emissions it is possible to understand the trajectory of pollutants from power plants. The Tata Energy Research Institute (TERI) has been recently conducted air quality studies for a number of power plants in the country. This paper firstly presents some of the major environmental concerns associated with thermal power generation, and the ways and means of mitigating these concerns. This is followed by a description of air quality modeling system and a brief overview of results for a typical large thermal power plant in India.

Air pollution from fossil-fuel based power plants

The composition of flue gases when coal is burnt are sulphur oxides (SO_x), nitrogen oxides (NO_x), carbon monoxide (CO), carbon dioxide (CO_2), suspended particulate matter (SPM) along with hydrocarbons, radionuclides and aldehydes. Emissions from oil-fired power plants are similar to those from coal-fired plants with a lesser degree of fly ash, whereas the only significant pollutant from a gas-fired power plant is NO_x. Without any kind of pollution control equipment, the uncontrolled emissions from a conventional 210 MW plant coal-fired power plant is about 1,80,000 tonnes annually of SO_x, NO_x and SPM. Table 1 shows air pollution effects of coal use with possible control measures.

Particulate emissions affect human beings in a number of ways (see Table 1). Control techniques are well established. Fly ash is controlled by Electrostatic-precipitators (ESP) which can separate particles greater than 0.1 micron m. ESPs can separate 99% of the mass concentration but in terms of actual number of particles only

Table 1 : Air pollution effects associated with coal use, and possible control measures

Effects	Control
Particulates (TSP)	
Act synergistically with other gases aggravate asthma, emphysema and cardiovascular diseases, cough, chest discomforts, reduce visibility, corrode steel.	Electrostatic precipitation etc.
Sulphur Oxides (SO_2)	
Increased mortality & morbidity, bronchitis, emphysema, chronic plant . injury, excessive leaf sheddings; reduced productivity of plants and trees.	Flue Gas Desulphurization systems. Dilution by using tall stacks.
Nitrogen Oxides (NO_x)	
Associated with emphysema, lung diseases, chronic nephritis, factor in causation of smog, yellow white clothes, fade synthetic fibres.	By modification of combustion processes, a reduction of 35 to 40% in emissions achievable without loss of thermal efficiency.
Carbon Monoxide (CO)	
Impairment of mental functions, diminished visual perception, dexterity learning ability, tolerance for exercise.	Largely controlled by having efficient & complete combustion.
Hydrocarbons (HCs)	
Lacrimation, coughing, sneezing, headaches, nervous weakness, bronchitis; chronic exposures may lead to cancer; act synergistically with NO_x to form photochemical oxidants & smog.	Same as for carbon Monoxide.
Carbon dioxide (CO_2)	
Could have global effects through the green house effect which could change local rainfall and temperature. The magnitude and timing are not known with certainty.	Prohibitively expensive to control CO_2 emissions; may require curtailment of fossil-fuel combustion.
Trace Elements	
Metals are preferably concentrated in the smallest respirable particles which are not removed by precipitators. Effects depend upon the metal. Hg., As and Cd may be of most concern.	Use of coal low in trace elements.
Radionuclides (Radium, Thorium, Radon)	
Mutagenic, carcinogenic	Isolation of humans from fly-ash exposure.
Polycyclic Organic Matter (POM)	
Most important constituent, Benzo(a) Pyrene, BaP, is highly carcinogenic.	Same as for CO.
Coal Dust	
Pnumoconiosis (Black Lung Disease)	Improved ventilation, dust suppression by water sprinklers.
Noise	
Hearing loss, psychological problems	Better equipment design, isolation of workers from noise, use of protective ear muffs.

5% is removed. A suggestion is to separate the flue into two streams and to charge each stream oppositely. This would lead to the formation of particles of a large size and hence a greater number (> 5%) would be absorbed by the precipitator. Other collection methods include bag house collectors and fabric filters.

The principal sulphur oxide emitted is sulphur dioxide (SO_2). Major impacts include health effects, corrosion effects and chronic plant injury. Methods of mitigation are 1) use of low sulphur coals and 2) installation of flue gas desulphurization (FGD) system.

Nitrogen oxides (NO_x) mainly consist of nitric oxide (NO) and nitrogen dioxide (NO_2). During the combustion process the nitrogen present in the air combines with oxygen and produces NO. This is a relatively non-irritating gas and is therefore believed to pose no health threat at ambient levels. However, NO rapidly oxidizes to NO_2, which has a much higher level of toxicity. Both NO and NO_2 are also important in the creation of photochemical oxidants (smog). It also has major impacts on human health (see Table 1). Methods of mitigating NO_x emissions are generally based on combustion modification techniques involving modification of burners and use of low NO_x burners. More advanced techniques involve flue gas denitrification using chemical process.

Environmental control costs are generally dominated by SO_2 control equipment. Capital cost for FGD (wet lime or limestone systems) are generally reported to be anywhere between 11% and 18% of total power plant cost with an average of 13% (data from USA, Japan, Germany). Operating costs range from 8% to 18% of total plant cost depending upon the extent of SO_2 removal.

ESP costs are about one-third the average investment of FGD. Annual revenue requirements also range from 10% to 30% of the requirements for FGD. Overall particulate removal contributes approximately 2% of total generating cost.

NO_x control cost depends on whether combustion modification of flue gas treatment is adopted. For the former capital costs are less than 1% of total plant costs. Annual operating cost on an average amounts to less than 0.5% of total plant operating costs. Flue gas treatment or denitrification is more expensive. In Japan where both systems have been used, the capital requirements are approximately 3% of total plant cost and operating cost being approximately 6% of the annual plant operating cost. Based on the above, a stringent environmental programme can result in up to 27% of total capital cost and total 30% annual revenue requirements. However, the range of costs would differ from country to country. On the other hand, even if a stringent environmental programme is not pursued, the society will be paying a heavier cost, although indirectly, in terms of health damages. But an attempt should be made to prevent or reduce the environmental damage at a cost which has techno-economic justification and is financially acceptable to the society.

Dispersion modelling

The real concern with pollution emission from power plants is the human exposure to these pollutants. The concentration level at ground level is an important indicator of human exposure along with emission rate and stack height. Even after implementing abatement measures by providing tall stacks and emission control technologies, it is not possible to withdraw the total pollutants from the flue gas. In some cases, where local atmospheric conditions are favourable, ground level concentrations can be taken care of with lower stack heights and few control technologies, and therefore at lesser costs. Thus, it is essential to assess the ground level concentrations for an existing or proposed power plant before taking any decision on expansion or siting of the plant.

To predict the ground level concentrations, it is necessary to simulate the atmospheric dispersion of pollutants under different conditions (wind speeds, stability, etc.) using air quality models. TERI has developed a computer simulation Gaussian Dispersion Model and applied to a number of power plants in India successfully. This model predicts the short-term and long-term pollutant concentrations with reference to the emission source, given the inputs of wind speed, wind direction, rate of emission by the source and atmospheric stability. The Gaussian Point Source Dispersion Model was chosen because this was found to be most suitable from the point of view of data availability and accuracy required. Gaussian models have been also recommended by Bureau of Indian Standards (1978, IS 8829).

The salient features of the TERI model are:

- algorithms are based on Gaussian plume modeling assumptions.
- model predicts the ground level concentrations (GLC), maximum GLC, distance at which maximum GLC occur and distance at which the plume touches the ground.
- model predicts short-term average, long-term average (seasonal, annual), long-term 95 percentile maximum and under worst possible atmospheric conditions (fumigation, trapping).
- GLC formula is calibrated for 8-hour averaging time since pollution boards are using 8-hour standards.
- ASME model is used for estimating dispersion coefficients.
- Wind speed at stack height is estimated using wind scaling factors.
- plume rise is calculated using the BIS recommendations.
- model includes correction for stack downwash, wash out due to rain and chemical reaction of pollutants.

A detailed presentation of the model is given in the following sections.

Model formulation

Basic principle

Upon discharge in to the atmosphere the emission from stationary sources are subjected to 1) an initial vertical rise called plume rise due to initial buoyancy and momentum of discharge b) tansport by wind in its direction and c) diffusion by turbulence.

Assumptions in the Gaussian model

a) Steady state conditions, ideal gas, continuous uniform emission rate, homogeneous horizontal wind field, representative mean wind velocity, no directional wind shear in the vertical plane and infinite plume.

b) Total reflection of the plume taking place at the earth's surface.

c) Gaussian distribution, i.e., the pollutant material within the plume takes a Gaussian distribution in both horizontal cross wind and vertical directions.

Basic equation

Concentration in air due to pollutants released into the atmosphere from a single continuous point source is calculated by Pasquill's relation modified by Gifford as follows:

$$C(x,y,z) = \frac{Q}{2\pi\, \sigma_y\, \sigma_z\, u} \exp\left[\frac{-1}{2}\left[\frac{y}{\sigma_y}\right]^2\right] \cdot \exp\left[\left[\frac{-1}{2}\left[\frac{Z-H}{\sigma_z}\right]^2\right] + \exp\left[\frac{-1}{2}\left[\frac{z+H}{\sigma_y}\right]^2\right]\right]$$

$C(x,y,z)$ = concentration of the pollutant at receptor point x, y, z from a continuous source, gms/m3

Q = emission rate of pollutant, gms/s

u = wind velocity along the x direction, m/s

y = cross wind distance, m

x = down wind distance, m

z = vertical height, m

H = effective stack height (hs + dh), m

σ_y = horizontal dispersion coefficient, m

σ_z = vertical dispersion coefficient, m

hs = stack height, m.

ds = plume rise, m.

Stability, mixing height, diffusion coefficient, wind scaling plume rise, stack downwash and chemical reaction which are part of the model are described below.

Atmospheric stability

Atmospheric stability is the term applied to the condition of the atmosphere that affects the vertical motions of air parcels. Atmosphere is unstable when the vertical motion is enhanced. This condition occurs when temperature decreases with height at a rate greater than 0.98°C per 100m. When the temperature lapse rate (rate of change of temperature with height) equals 0.98°C per 100m, the atmosphere is said to be neutral and vertical motions are not affected. This lapse rate is called dry adiabatic lapse rate. When the temperature decreases with height at a rate less than the adiabatic or when temperature increases with height (temperature inversion) vertical motions are damped and the temperature is called stable. Intensity of turbulence and therefore the atmospheric diffusion increases with instability of the atmosphere and decreases with increasing stability of the atmosphere. Atmospheric stability is controlled by insolation, nocturnal radiation loss and wind speed. The following studies have been conducted to formalize the relationships between atmospheric surface stability and those factors controlling stability i.e. insolation, nocturnal radiation and meteorology.

- Pasquill stability categories

A classification of stability in accordance with the wind speed and incoming solar radiation for day or cloud cover for night.

- Brokhaven stability categories

A classification of stability in accordance with wind direction fluctuations.

- TVA stability categories

A classification of stability in accordance with the temperature.

Of the three, the Pasquill method is the most commonly used for the determination of stability class. Pasquill model defines six classes of stability. The selection procedure is shown in Table 2.

Mixing height (MH)

The height of the base of the inversion above the ground level is called mixing height. This layer limits the vertical dispersion. If vertical mixing is limited, pollutants emitted from a point source in to the mixing layer will be trapped and, beyond some point downwind, will become uniformly mixed in the vertical. Mixing layer can be estimated by using a simple model, by knowing the temperatures at different elevations. The model assumes that the environmental lapse rate is a constant. Then,

$$H_m = \frac{T_{max} + C/m}{1/m - 1/m1}$$

Where

$$C = \frac{T_1Z_2 - Z_1T_2}{T_1 - T_2}$$

and

$$m = \frac{Z_1 - Z_2}{T_1 - T_2}$$

H_m = Afternoon mixing height, m
T_{max} = maximum temperature of the day °C
T_1 & T_2 = temperatures (°C) at height Z_1 and Z_2 respectively
m_1 = - 100 (reciprocal of adiabatic lapse rate) in m/°C

Dispersion coefficients

Dispersion coefficients σy and σz are standard deviations of distributions of concentrations in horizontal cross wind and vertical directions respectively. These are dependent on the atmospheric stability and the downwind distance. The quantities σy and σz increase with increasing downwind distance x, signifying that the dilution increases with distance. The rate at which σy and σz increase will depend upon the turbulence intensity, and hence stability of the atmosphere. There are three models in use for estimation of dispersion coefficients – Pasquill-Giffords, TVA, and ASME. In the present study American Society of Mechanical Engineers (ASME) model is used for estimation of dispersion coefficients. The ASME model has four stability classifications – a) very unstable, b) unstable, c) neutral, and d) stable.

The standard deviation σy and σz are given in terms of power laws:
$\sigma y = ax^p$
$\sigma z = bx^q$

Table 3. gives the values of a,b,p,q for these four cases. The averaging time for dispersion coefficients in ASME method is one hour.

Table 3. Values of a,b,p,and q in the ASME model

stability	a	b	p	q
very unstable	0.4	0.91	0.4	0.91
unstable	0.36	0.86	0.36	0.86
neutral	0.32	0.78	0.22	0.78
stable	0.31	0.71	0.06	0.71

Scaling of wind speed (wind speed at stack height)

In the layer of the atmosphere above the ground, wind speed changes with the height. Generally it increases with height, but strongly depends upon the stability condition of the atmosphere. The wind speed at the stack height was computed based on following power law:

$U1 = U2(Z1/Z2)^p$

where
U1 = wind speed at height Z1 above MSL, m/s
U2 = wind speed at height Z2 above MSL, m/s
Z1 = stack height, m
Z2 = elevation of meteorological station above MSL, m
p = wind profile component

The exponent p is dependent on atmospheric stability and has a value between 0 to 1. Table 4 shows recommended values of exponent p.

Table 2. Pasquill stability classes

Surface wind speed (at10mt)	Daytime Insolation			Night time condition	
	Strong	Moderate	Slight	Thick overcast or < =4/8 cloud cover	> = 3/8 cloud cover
(1)	(2)	(3)	(4)	(5)	(6)
2	A	A-B	B	-	-
2-3	A-B	B	C	E	F
3-5	B	B-C	C	D	E
5-6	C	C-D	D	D	D
6	C	D	D	D	D

A - Extremely unstable
B - Moderately unstable
C - Slightly unstable
D - Neutral
E - Slightly stable
F - Moderately stable

Table 4. Wind speed profile exponent as a function of stability

Pasquill stability class	A	B	C	D	E	F
p	0.15	0.17	0.20	0.26	0.39	0.48

Wind rose

Wind speed and direction are the basic meteorological parameters which affect the plume rise and transportation of pollutants discharged into the atmosphere from the sources. Theoretical considerations show that the concentrations are inversely proportional to wind speed. In the layer of the atmosphere above the ground, wind speed varies with height. Generally, it increases with height. These two basic wind parameters i.e. speed and direction are expressed in the form of a frequency table or in a wind rose form. Wind rose or frequency table gives the frequency or time with which wind blows with a particular speed and direction. The wind direction represents the direction from which the wind is blowing. Wind rose represents 8 or 16 wind directions with each direction making an angle of 45° or 22.5° with the next. Wind speed is expressed in m/s or km/hr or in knot (1 mile/hr). Wind rose is generally expressed for a month, a season or a year, based on the levels of variation of wind direction.

Plume rise

Plume rise, which is given by the elevation of the plume centre line above the stack outlet, depends upon the initial flux of momentum (exit velocity) and heat passing through the stack exit. There are over 20 plume rise emissions that have appeared in the literature and new ones are being proposed annually. For this study, the plume rise equation recommended by B.I.S is used.

$$Qh = Qm(Ts-Ta)Cp \qquad ...... (7)$$

for $Qh \geq 10^6$ cal/sec

$$dh = 0.84 * (12.4 + 0.09H) * Qh^{0.25}/U \qquad ...... (8)$$

otherwise,

$$dh = 3 \, Ve \, D \, / \, U \qquad ...... (9)$$

where

Qm = emission rate, gm/s

Ts = efflux temperature, °K

Ta = ambient temperature, °K

Cp = specific heat capacity, cal/gm °K

Cp is taken as 0.255 for oil, 0.265 for natural gas, and 0.255 for coal

H = physical height of the stack, m

U = wind speed at stack height, m/s

Ve = efflux velocity, m/s

D = stack diameter, m

Stack downwash

When a plume meets an obstacle (natural or manmade), the obstacle causes a separation of flow around it, and generates turbulence in the wake, thus forming a cavity behind the obstacle and pollutants gets entrained into this cavity causing high concentrations. Such an effect is called stack downwash. Downwash of plume in to the low pressure region in the wake of a stack can occur if the efflux velocity is too low. The effects of stack downwash is incorporated through a modified expression for the plume rise by multiplying a factor 'f' to the plume rise. The calculated plume rise is multiplied by this factor and then is used in the dispersion calculation.

$$f = 1 \text{ if } u \leq v_e/1.5 \qquad ...... (10)$$

$$f = 3 \times v_e - u/v_e \text{ if } v_e/1.5 \leq u < v_e \qquad ...... (11)$$

$$f = 0 \text{ if } u \geq v_e \qquad ...... (12)$$

where v_e is efflux velocity in m/s,
u is wind velocity at stack height

Chemical reaction

Oxides of nitrogen and sulphur undergo chemical reactions and the concentration expression should be multiplied with the term

$$CR = \exp(-0.693x/uT_{1/2}) \qquad ...... (13)$$

where x is the downwind distance and $T_{1/2}$ is the chemical half life of the pollutants.

Rain wash out

Falling drops of precipitation pick up particulate matter and soluble gases vapours in their path. This leads to depletion of pollutants from the atmosphere. The depletion of concentration due to washout may be computed by multiplying the concentrations obtained from air quality model by the wash out correction factor (FR).

$$FR = \exp\left[\frac{-\Omega x}{u}\right] \qquad ....(14)$$

$$\Omega = 5.9*10^{-4} Y.r^{0.59} (S^{-1}) \qquad .....(15)$$

where

Ω = rain washout coefficient

Y = molecular diffusivity in cm^2/s of the gas

r = rainfall rate in mm/n

Short term concentrations

The short term concentrations is estimated by the equation 1.For concentrations calculated at ground level i.e. z = 0 and at plume centre line i.e. y=0 the expression becomes

$$C(x,O,O) = \frac{Q}{\pi \, \sigma y \, \sigma z \, u} \exp\left[\frac{-1}{2}\left[\frac{H}{\sigma z}\right]^2\right] \qquad ...(16)$$

The point at which maximum concentration occurs is

$$x_{max} = \left[\frac{H^2 d}{(b+d)C^2}\right]^{(1/2d)} \qquad ......(17)$$

where b,c,d are parameters associated with the dispersion coefficients.

The maximum ground level concentration is given by

$$(GCL)_{max} = C(X_{max},O,O) = \frac{Q}{\pi \sigma y_{max} \sigma z_{max} u}\left[\exp \frac{-1}{2}\left[\frac{H}{\sigma z_{max}}\right]^2 + \exp\left[\frac{-(Z + 2JHm + H)^2}{2\sigma z^2}\right]\right]$$

with $J = O, \pm 1, \pm 2 \ldots\ldots \pm \infty$

where Hm is the height of mixing layer in metres. The summation of infinite series can be terminated for $n = 5$ which is reported to be adequate (Turner, 1970). This equation accounts for multiple eddy reflections from both the ground and the stable layer.

Averaging time calibration

Concentrations obtained by using the values of ASME dispersion coefficients would be valid only for the one hour sampling time for which σy and σz are also valid. To convert one hour sampling time to eight hour sampling time following power law function of time ratio is used:

$$c_s/c_1 = (t_1/t_s)^{\alpha} \qquad \ldots\ldots (19)$$

B.I.S has suggested a value of 0.4 for α. Such a relationship is valid in the range of 3 minutes to 24 hours.

Long term averaging

Long term (seasonal, annual) averages of the concentrations of the various pollutants needed to evaluate the effectiveness of air pollution control strategies or to ascertain the impact of projected industrial or residential growth in compliance with the ambient air quality standards. The meteorological factors that are used in calculation of the concentrations are the wind speed, wind direction, and stability class. If there are n wind speed classes, S stability classes and θ wind directions then long term average of the concentration at a distance x in wind direction θ is given by

$$C(x,\theta) = \sqrt{2/\pi}\ \frac{Q}{100(2\pi n/\theta)} \sum_N \sum_S \frac{f(\theta,N,S)}{Un\ \sigma Z^{*}S} \exp\left[\frac{-1}{2}\ \frac{H^2}{\sigma Z^2 S}\right]$$

where

$f(\theta,S,N)$ = the percentage frequency during the period of interest that the wind is from the direction θ, for the stability condition S and the wind speed class n.

U_n = mid value of the wind speed of class N

σ_{zs} = vertical dispersion coefficient corresponding to stability class S.

θ = angle representing wind direction

Worst possible scenarios

The worst case is useful in identifying the most serious or greatest that will occur in a given year. Trapping and fumigation are the two worst cases of atmospheric conditions which can lead to episodic conditions.

Trapping

Plume trapping occurs when the plume is trapped between the ground surface and a stable layer aloft (increase). Following equation is used in estimating the concentrations under trapping condition:

$$Ct(X,Y,Z,H) = \frac{Q}{2\pi\sigma_y\sigma_z u} \exp\left[\frac{-y^2}{2\sigma y^2}\right] s - \left[\frac{Z}{\sigma z}, \frac{H}{\sigma z}, \frac{Hm}{\sigma z}\right]$$

where

$$S\left[\frac{Z}{\sigma z}, \frac{H}{\sigma z}, \frac{Hm}{\sigma z}\right] = \sum_J \left[\left[\exp \frac{-(Z + 2JHm - H)^2}{2\sigma z^2}\right.\right.$$

Fumigation

When the ground is being warmed by solar radiation or when air flows from a cold to a relatively warm surface, a surface based inversion may be eliminated by the upward transfer of sensible heat from the ground surface. This situation usually occurs for a short duration at mid-morning, wherein pollutants previously emitted above the surface into a stable layer will be mixed downward vertically when they are reached by the thermal eddies, and ground level concentrations can become very high. This process is described as fumigation. To estimate ground level concentrations under inversion break-up fumigations, one assumes that the plume was initially emitted into a stable layer. Therefore σy and σz characteristic of stable conditions must be selected for the particular distance of concern. An expression for ground level concentration is given below:

$$C(x,0,0) = \frac{Q}{1.1\sqrt{2\pi}\ \sigma_{yf}\ H_f u}$$

where

$\sigma_{yf} = \sigma_y + 0.47H$

and

$H_f = H + 2.15\,\sigma z$

Model application and results

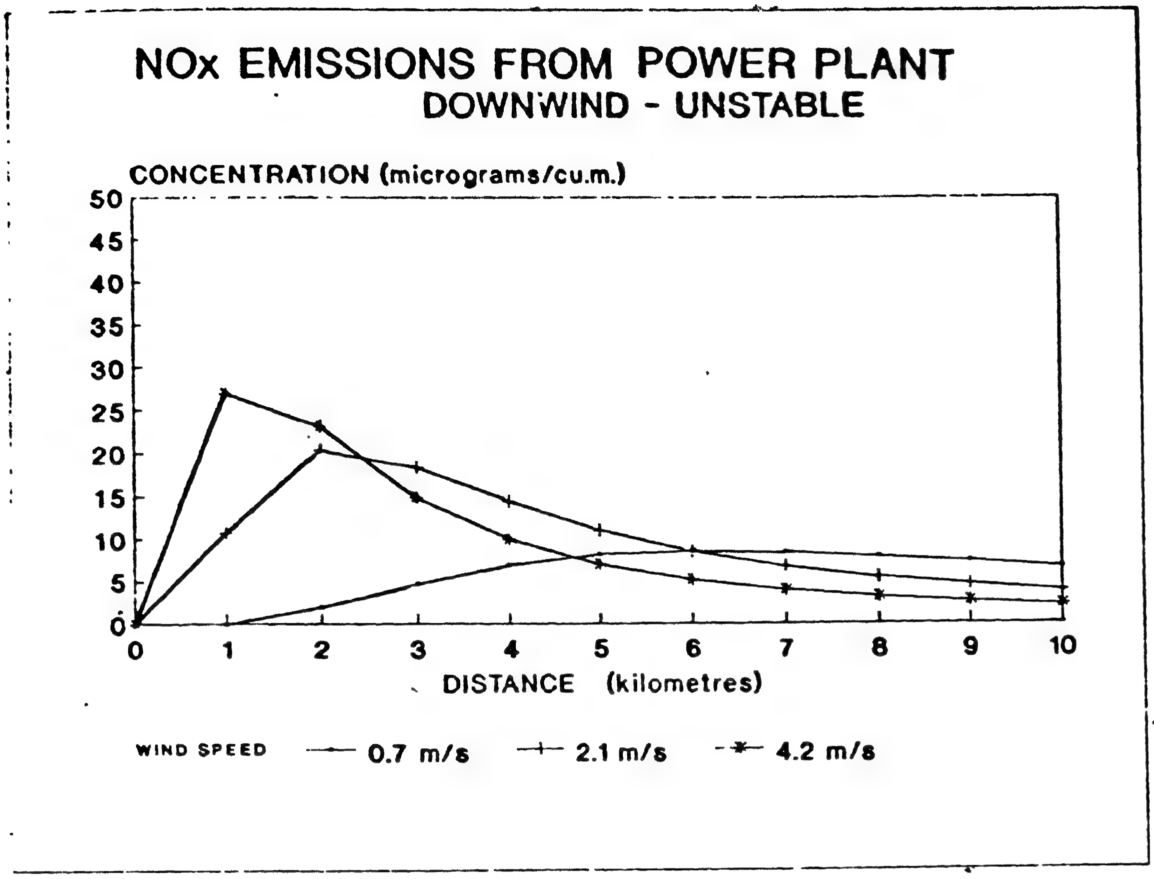
The model described earlier is applied to a large typical thermal power plant in India. The spatial and temporal variations in concentrations under different condition are modelled. The results are presented only for the NO_x pollutant. A spatial scale of 10 km is used. The time scale used is short-term (8-hr average) and long-term (95% seasonal maximum). Table 5 gives a description of the power plant, project region and meteorological conditions of the region.

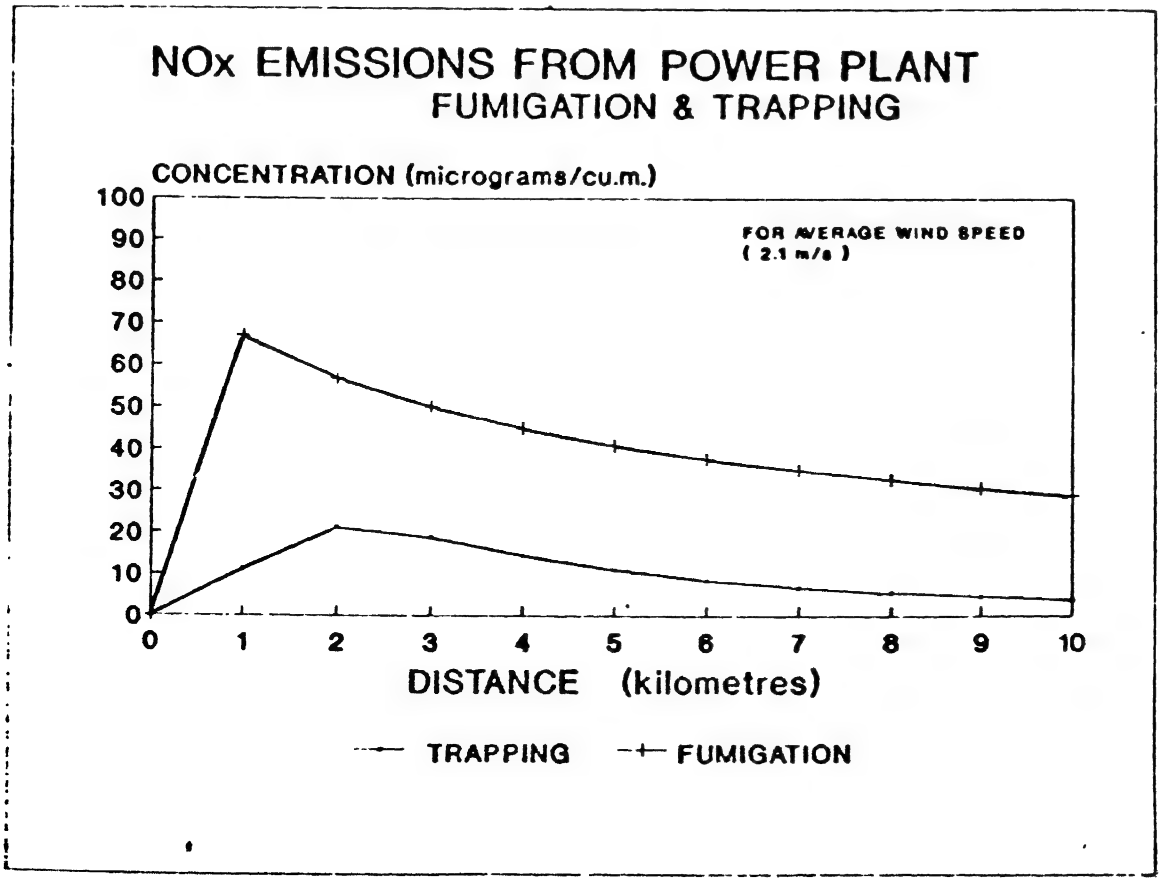
Short-term averages

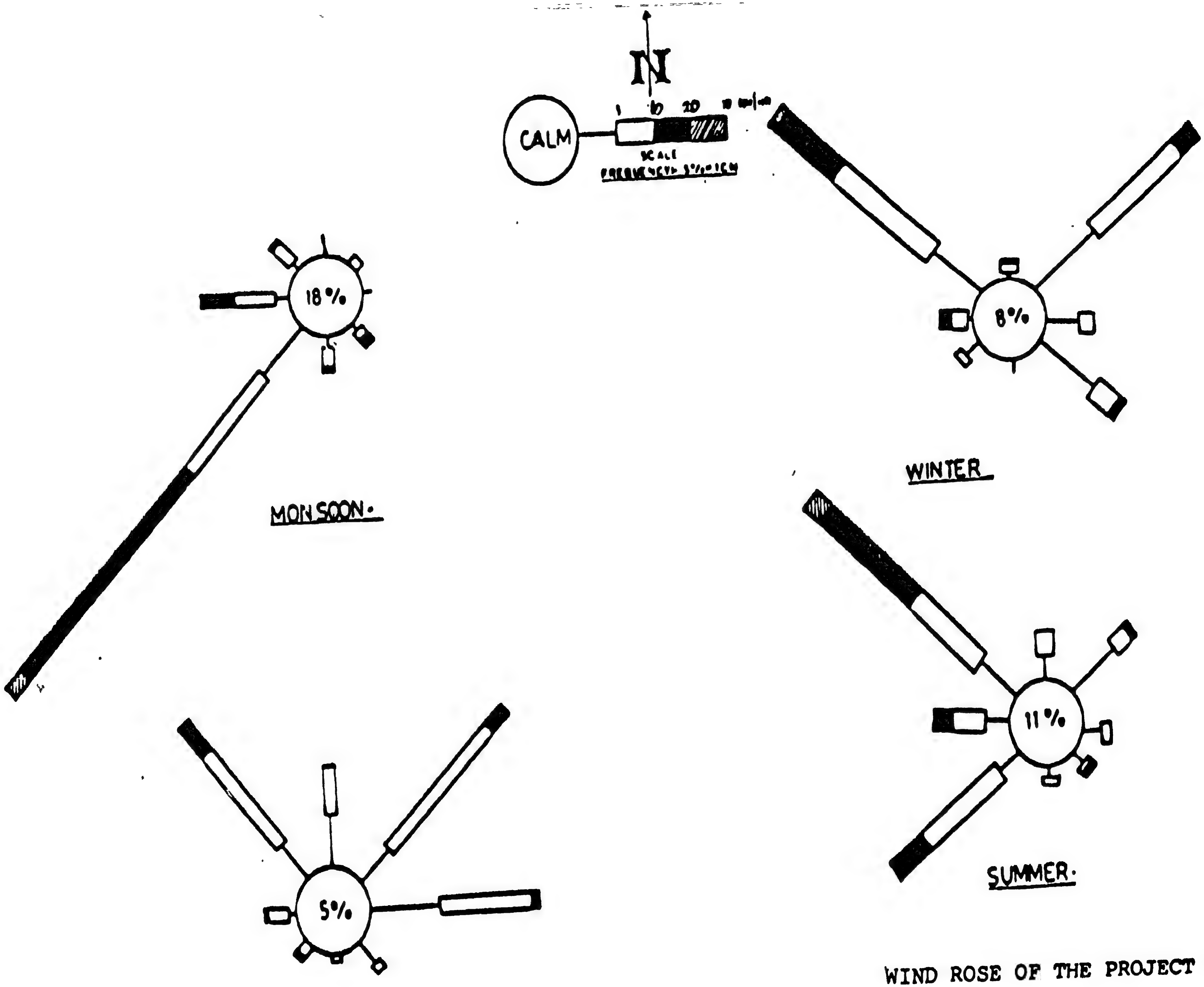
To cover the entire range of wind speeds and stability the model was initially run for unstable, neutral and stable atmospheric conditions for three wind speeds that ranged from low (.7 mps), average (2.1 mps) to a high of 4.2 mps. It was observed that stable and neutral conditions give rise to very high plume rise and consequently very low GLCs in the range of 10 km. However, unstable conditions give rise to higher levels of GLCs. Figure 1 shows GLCs for three wind speeds for unstable conditions.

It is observed that higher wind speeds produced higher GLCs nearer to the plant (27 ug/m^3, 4.2 m/s, 1 km; 20 ug/m^3, 2.1 m/s, 2 kms; and 8 ug/m^3, .7 m/s, 7 km). However, at distances greater than 6 km higher wind speeds produced lower concentrations (4 ug/m^3, 4.2 m/s, 8 km; 6 ug/m^3, 2.1 m/s, 8 km; and 8 ug/m^3, .7 m/s, 8 km). This is because wind speeds affect GLCs in two ways. Higher wind speeds produces lower plume rise which in turn increase GLCs nearer to the plant. However, higher wind speeds also increase dispersion and therefore, at farther distances there is a reduction in GLCs.

FIGURE 1


NOx EMISSIONS FROM POWER PLANT
DOWNWIND - UNSTABLE
CONCENTRATION (micrograms/cu.m.)
50
45
40
35
30
25
20
15
10
5
0
0
1
2
3
4
5
6
7
8
9
10
DISTANCE (kilometres)
WIND SPEED
0.7 m/s
2.1 m/s
4.2 m/s


NOx EMISSIONS FROM POWER PLANT
FUMIGATION & TRAPPING
CONCENTRATION (micrograms/cu.m.)
FOR AVERAGE WIND SPEED
(2.1 m/s)
100
90
80
70
60
50
40
30
20
10
0
0
1
2
3
4
5
6
7
8
9
10
DISTANCE (kilometres)
TRAPPING
FUMIGATION



WIND ROSE OF THE PROJECT REGION

Table 5 Description of plant and project region

Total rating (6 units together)	1430 MW
No. of stacks	5
Height of stack above ground level (m)	Range : 76-275
Diameter of stacks (m)	Range : 5.4-7.3
Flue gas quantity (m^3/sec)	1581 from all the units together
Exit velocity of gas (m/sec)	Range : 8-25
Temperature of flue gas (°C)	Range : 120-140
Total NO_x emissions from all the units together (gms/sec)	270
Ambient temperature (°C)	Range : 23.3-30 with mean value at 26
Seasons	Winter, Summer, Monsoon, Post-monsoon
Wind speeds (m/sec)	Ranging from 0.7-4.2 with average speed of 2.1
Predominant wind direction	Winter: North-East/East and North-West; Summer: North-West and South-West; Monsoon: South-West; Post-Monsoon: East, North-East, North-West
Mixing Height(m)	Range from 530-2000 with mean height of 700
Stability	Region has stable atmosphere 1/3rd of time, neutral conditions for 1/4 of time. Stable conditions are predominant in the winter with unstable in summer and neutral in monsoon and post-monsoon

Trapping and fumigation

Results for both fumigation and trapping are shown in Figure 2 Fumigation conditions produce higher GLCs with concentrations reaching a maximum of 67 ug/m^3 at a distance of 1 km.

Seasonal 95 percentile maximum levels

The long-term 95 percentile maximum levels were determined for winter, summer, monsoon and post-monsoon seasons. For a given stability and the wind rose for the season, the model calculates GLCs at increasing distances for each direction of the wind rose. Table 6 shows GLCs in different direction for all the seasons.

Winter records the highest levels of concentrations with a maximum value of 64 ug/m^3 in the areas located at South-West and South-East. This is because of predominance of trapping conditions in this season. Because of trapping phenomenon, plume does not touch the ground before 9 kms. Concentrations are maximum in South-West and South-East parts of the region as the predominant wind direction is from North-East and North-West.

In summer months, winds are predominantly from the North-West, North-East and South-West directions resulting in concentrations along the North-East (12 ug/m^3), South-West (6 ug/m^3) and South-East (12 ug/m^3).

In monsoon season, winds are from the South-West and concentrations are therefore in the North-East direction having a level of 7 ug/m^3. This is primarily due to wash out as well as due to neutral stability which gives rise to high plume rise.

During post-monsoon period, winds blow from the East to the North-West resulting in pollution from the West to the South-East (5ug/m^3). This is again low because the atmospheric stability is neutral.

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Table 6 : SEASONAL 95% MAXIMUM VALUES

WINTER SEASON

DISTANCE (MTS)	CONCENTRATION IN THE DIRECTION							
	W	SW	S	SE	E	NE	N	NW
9000	20.90	64.20	0.00	64.20	0.00	0.00	0.00	0.00
10000	18.95	57.40	0.00	57.40	0.00	0.00	0.00	0.00
11000	17.43	52.70	0.00	52.70	0.00	0.00	0.00	0.00
12000	15.95	48.20	0.00	48.20	0.00	0.00	0.00	0.00
13000	14.80	44.70	0.00	44.70	0.00	0.00	0.00	0.00
14000	13.66	41.27	0.00	41.27	0.00	0.00	0.00	0.00
15000	12.74	37.90	0.00	37.90	0.00	0.00	0.00	0.00
16000	11.94	35.65	0.00	35.65	0.00	0.00	0.00	0.00
17000	11.25	33.40	0.00	33.40	0.00	0.00	0.00	0.00
18000	10.66	32.05	0.00	32.05	0.00	0.00	0.00	0.00
19000	10.10	29.81	0.00	29.81	0.00	0.00	0.00	0.00
20000	9.53	28.48	0.00	28.48	0.00	0.00	0.00	0.00
21000	9.18	27.75	0.00	27.75	0.00	0.00	0.00	0.00
22000	8.62	26.12	0.00	26.12	0.00	0.00	0.00	0.00
23000	8.27	24.59	0.00	24.59	0.00	0.00	0.00	0.00
24000	8.03	24.17	0.00	24.17	0.00	0.00	0.00	0.00
25000	7.68	22.74	0.00	22.74	0.00	0.00	0.00	0.00

SEASONAL 95% MAXIMUM VALUES

MONSOON SEASON

DISTANCE (MTS)	CONCENTRATION IN THE DIRECTION							
	W	SW	S	SE	E	NE	N	NW
1000	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.00
2000	0.00	0.00	0.00	0.00	0.07	2.02	0.00	0.00
3000	0.00	0.00	0.00	0.00	0.74	4.08	0.00	0.00
4000	0.00	0.00	0.00	0.00	1.71	5.57	0.00	0.00
5000	0.00	0.00	0.00	0.00	2.57	6.40	0.00	0.00
6000	0.00	0.00	0.00	0.02	3.27	6.78	0.02	0.00
7000	0.00	0.00	0.00	0.05	3.74	6.98	0.05	0.00
8000	0.00	0.00	0.00	0.12	3.99	7.04	0.12	0.00
9000	0.00	0.00	0.00	0.21	4.23	6.80	0.21	0.00
10000	0.00	0.00	0.00	0.31	4.43	6.40	0.31	0.00
11000	0.00	0.00	0.00	0.43	4.57	6.04	0.43	0.00
12000	0.00	0.00	0.00	0.53	4.63	5.60	0.53	0.00
13000	0.00	0.00	0.00	0.65	4.42	5.46	0.65	0.00
14000	0.00	0.00	0.00	0.77	4.21	5.22	0.77	0.00
15000	0.00	0.00	0.00	0.87	4.01	5.09	0.87	0.00
16000	0.00	0.00	0.00	0.99	3.84	4.86	0.99	0.00
17000	0.00	0.00	0.00	1.07	3.67	4.64	1.07	0.00
18000	0.00	0.00	0.00	1.16	3.58	4.47	1.16	0.00
19000	0.00	0.00	0.00	1.23	3.34	4.31	1.23	0.00
20000	0.00	0.00	0.00	1.32	3.20	4.06	1.32	0.00

SEASONAL 95% MAXIMUM VALUES .

SUMMER

DISTANCE (MTS)	CONCENTRATION IN THE DIRECTION							
	W	SW	S	SE	E	NE	N	NW
1000	0.00	0.02	0.02	31.80	13.01	13.01	0.00	0.00
2000	0.00	2.61	2.61	28.40	21.59	24.50	0.00	0.00
3000	0.00	6.13	5.81	22.40	17.78	22.20	0.00	0.00
4000	0.00	8.76	7.20	17.90	11.84	17.90	0.00	0.00
5000	0.00	10.27	8.45	14.09	9.77	14.09	0.00	0.00
6000	0.00	·10.72	8.11	12.02	8.31	12.02	0.00	0.00
7000	0.00	10.42	6.97	10.72	6.97	10.72	0.00	0.00
8000	0.00	9.58	5.83	9.58	5.83	9.58	0.00	0.00
9000	0.00	8.83	4.77	8.83	4.77	8.83	0.00	0.00
10000	0.00	7.96	4.05	7.96	4.05	7.96	0.00	0.00
11000	0.00	7.15	3.37	7.15	3.37	7.15	0.00	0.00
12000	0.00	6.47	2.93	6.47	2.93	6.47	0.00	0.00
13000	0.00	5.74	2.55	5.74	2.55	5.74	0.00	0.00
14000	0.00	5.22	2.21	5.22	2.21	5.22	0.00	0.00
15000	0.00	4.73	1.90	4.73	1.90	4.73	0.00	0.00
16000	0.00	4.35	1.72	4.35	1.72	4.35	0.00	0.00
17000	0.00	3.88	1.54	3.88	1.54	3.88	0.00	0.00
18000	0.00	3.62	1.38	3.62	1.38	3.62	0.00	0.00
19000	0.00	3.27	1.24	3.27	1.24	3.27	0.00	0.00
20000	0.00	2.97	1.14	2.97	1.14	2.97	0.00	0.00

POST-MONSOON

SEASONAL 95% MAXIMUM VALUES

DISTANCE (MTS)	CONCENTRATION IN THE DIRECTION							
	W	SW	S	SE	E	NE	N	NW
1000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2000	0.07	0.07	0.00	0.07	0.00	0.00	0.00	0.00
3000	0.76	0.76	0.00	0.76	0.00	0.00	0.00	0.00
4000	1.74	1.74	0.00	1.74	0.00	0.00	0.00	0.00
5000	2.60	2.60	0.00	2.60	0.00	0.00	0.00	0.00
6000	3.36	3.36	0.02	3.36	0.00	0.00	0.00	0.00
7000	3.95	3.95	0.05	3.95	0.00	0.00	0.00	0.00
8000	4.52	4.52	0.12	4.52	0.00	0.00	0.00	0.00
9000	4.85	4.85	0.21	4.85	0.00	0.00	0.00	0.00
10000	5.00	5.00	0.32	5.00	0.00	0.00	0.00	0.00
11000	5.16	5.16	0.43	5.16	0.00	0.00	0.00	0.00
12000	5.20	5.20	0.56	5.20	0.00	0.00	0.00	0.00
13000	5.15	5.15	0.67	5.15	0.00	0.00	0.00	0.00
14000	4.99	4.99	0.78	4.99	0.00	0.00	0.00	0.00
15000	4.93	4.93	0.88	4.93	0.00	0.00	0.00	0.00
16000	4.77	4.77	1.01	4.77	0.00	0.00	0.00	0.00
17000	4.62	4.62	1.11	4.62	0.00	0.00	0.00	0.00
18000	4.47	4.47	1.22	4.47	0.00	0.00	0.00	0.00
19000	4.32	4.32	1.32	4.32	0.00	0.00	0.00	0.00
20000	4.18	4.18	1.41	4.18	0.00	0.00	0.00	0.00

A Rational Assessment of T & D Losses in Indian Power Systems and Investment Requirements on T & D

L.R. SURI* and S.K. MUKERJEA**

1. Introduction

1.1 As is well known, the Transmission and Distribution losses in Indian Power Systems are rather high. According to Central Electricity Authority (CEA) statistics, on an All-India basis the losses which were about 20.44% in 1979-80 have steadily increased over the years, the estimated provisional figure for 1985-86 being of the order of 22%. According to the estimates of a few other independent agencies, the real T & D losses are much higher than those revealed by CEA statistics, and recently a figure of 25% losses was quoted for 1985-86. No doubt the practice followed by some State Electricity Boards of diverting a portion of unaccounted energy losses towards unmetered power supply to agriculturists suppresses the real level of T & D losses. It would therefore not be unreasonable to assume that the present level of actual T & D losses in Indian Power Systems is in the neighbourhood of 23%.

1.2 It would be interesting to compare the losses in our power systems with those in some of the more developed countries. According to available statistics (U.N. Annual Bulletin of Electrical Energy Statistics for Europe), the T & D losses are 8.52% (1983) in Canada, 7.30% (1982) in France, 8.22% (1978) in USSR and 8.80% (1976) in USA. It has also been reported that even China has been able to contain its T & D losses to 8% level. When viewed against these loss figures lying in the range of 8 to 9%, the prevailing T & D loss figure of 23% in our power systems looks to be too high. One must however consider whether it is logical to compare the T & D losses in our power systems with those in the more developed countries since the relevant basic parameters differ widely. To name a few, the size and stage of development of the primary and secondary distribution networks, the relative importance attached to T & D systems in the overall planning strategy of power development of the country, relative investments made in the distribution works vis-a-vis the investments in generation, transmission and Rural Electrification sectors are vastly different say for USA, Canada, USSR, etc., compared to India. For instance in USA approximately 50% of the capital investment in electrical power systems has been in distribution equipment. It is, therefore, not justifiable to compare the losses in Indian systems with the corresponding figures in other countries without taking into account the underlying factors mentioned above. Under the circumstances, it is meaningless to set targets for limiting the T & D losses in the foreseeable future in Indian systems to 8-9% level as in some of other countries. The Rajadhyaksha Committee on Power (1980) who had made an in-depth study of the problem, has recommended a realistic target of reduction of T & D losses by 1% every five years setting a target of 15% by 2000/01 AD. It would be relevant to mention in this connection that according to studies carried out by EPRI (Electric Power Research Institute, USA), depending on various relevant technical and other factors, the T & D losses should lie in the range of 8.25% to 15.5%. It is suggested that we may strive to achieve a target of reducing the T & D losses to 15% in the foreseeable future as recommended by Rajadhyaksha Committee.

1.3 In order to estimate the cost-effectiveness of the various modern techniques available for reduction of T & D losses in the context of Indian environment, it is essential to have an idea regarding the energy losses taking place at the various stages of transmission and distribution of power as well as a further break-up of the line losses and transformation losses. However, reliable and systematic data of this nature is not readily available for Indian Power Systems. In the present paper an attempt has been made to work out these losses on the basis of whatever relevant data are available.

2. Assessment of Breakup of Present 23% Losses

2.1 For making an assessment of the losses occurring at EHT (220, 132 & 66 kV) transmission and transformation, 33 kV level subtransmission and transformation, 11 kV primary distribution and finally in L.T. lines, a simplified model of the Transmission and Distribution System, by and large representing a typical Indian system in regard to voltage levels, conductor sizes used, usual ranges of voltage regulations and KVA-KM loadings, power factor of the loads, etc., has been considered. For working out these basic parameters an exercise was carried out in regard to a few SEB systems—in respect of Punjab and Haryana State Electricity Boards in the North,

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for M.P. and Maharashtra Electricity Boards in the West and for Tamil Nadu and Andhra Pradesh Electricity Boards in the South. It would be appreciated that in this sort of exercise it is impossible to arrive at precise values of parameters and a large amount of judgement has to be exercised to arrive at overall typical representative values.

2.2 The following Table (Table I) summarises the result of the study carried out to arrive at a possible break-up of the losses (23%) taking place at each voltage level. The basic assumptions in regard to the model of the typically representative Transmission and Distribution system taken for the exercise are also indicated in the Table. It may be mentioned that in the exercise the emphasis is on 33 kV, 11 kV and LT levels where the losses are unduly high and amenable to reduction. On the basis of available data it has been assumed that out of the total T & D losses of 23%, Transmission losses account for 4.5% and balance 18.5% are taking place in the 33 kV-11 kV-LT system.

3. Assessment of Break-up of 15% Losses Targetted to be Achieved in the Foreseeable Future

3.1 Out of total 15% T & D losses targetted to be achieved, it has been assumed that it would be possible to restrict the contribution of EHT losses to 3.5% (as against the present level of 4.5%) by various technical means like achieving optimal reactive balance in the EHT network, adoption of higher transmission voltages, improved grid management and operation techniques etc. Further, the normal development of the EHT network to handle the additional generation becoming available in the grid over the years would also help in reduction of losses at EHT level. Thus the task to reduce the T & D losses from 23% level to 15% level comprises reduction of EHT transmission losses from 4.5% to 3.5%, and the 33 kV-11 kV-LT losses from 18.5% to 11.5% level.

3.2 The exercise carried out with the representative model of the 33 kV-11 kv-LT indicates that the voltage-level-wise break-up of the losses is likely to be as given in Table II. This table also indicates the basic parameters in regard to line loadings, P.F. etc. that have to be achieved to restrict the losses to 11.5% at the sub-transmission, primary distribution and L.T. level.

4. Measures to be Adopted for Reduction of T & D Losses from Present 23% Level to 15% Level

4.1 A comparison of Tables I & II would indicate the reductions to be achieved at each voltage level (vide Table III). The measures that are required to be adopted for this purpose are indicated in the last column of Table III.

4.2 The technical measures for reducing the T & D losses discussed above are capital intensive. Considering the financial constraints of the SEBs, the steps to be taken for loss reduction should be highly cost-effective, i.e., the objective would be to adopt such measures which yield quick and substantial benefits with minimum financial investments. In this context it would be interesting to work out the respective contributions of the two factors viz. P.F. Improvement and reduction of line loading in achieving the total loss reduction of 1.25% at 33 kV, 2.75% at 11 kV and 3.0% at L.T. Level (vide Table III).

5. Estimation of Benefits due to P.F. Improvement and Other Measures

5.1 Table IV indicates the break-up of benefits achieved due to the measures mentioned in Table II.

TABLE I

Assessment of Break-up of Present Total T & D Losses of 23%

Sl. No.	*Voltage Level*	*Conductor*	*Average P.F.*	*Feeder Loading*	*Voltage Regulation Computed*	*Losses*		
						Line	*Transformation*	*Total*
1	2	3	4	5	6	7	8	9
1.	E.H.T. (220/132/66 kV)	—	—	—	—	4%	0.5%	4.5%
2.	33 kV	Raccoon	0.80	145 (MW-KM)	9%	3%	1%	4.0%
3.	11 kV	Squirrel	0.75	8.5 (MW-KM)	13%	5.7 } 6.0%	1%	7.0%
		Weasel		12.0 (MW-KM)		6.3		
4.	L.T. (415 V)	Squirrel	0.70	12.5 (KW-KM)	11%	5.4 } 5.5%	2%	7.5%
		Weasel		14.0 (KW-KM)		5.6		
							Total	23.0%

TABLE II

Assessment of Break-up of Total T & D Losses of 15% Targetted to be Achieved in the Foreseeable Future

Sl. No.	Voltage Level	Conductor	Average P.F.	Feeder Loading	Voltage Regulation Computed	Losses: Line	Losses: Transformation	Losses: Total
1.	EHT (220/132 66 kV)	—	—	—	—	3%	0.5%	3.50%
2.	33 kV	Raccoon	0.85	105 (MW-KM)	*6%	2%	0.75%	2.75%
3.	11 kV	Weasel	0.80	8.5 (MW-KM)	*9%	3.5%	0.75%	4.25%
4.	L.T. (415 V)	Squirrel Weasel	0.75	7.0 (KW-KM) 8.0 (KW-KM)	*6%	2.83 2.64 } 2.75	1.75	4.50%
							Total	15%

Note:

*According to statutory requirements the permissible voltage variations from the declared supply voltages are:

Low and Medium Voltage	:	±6%
High Voltage	:	+6%
	:	−9%
Extra High Voltage	:	+10%
	:	−12.5%

TABLE III

A Comparison of Present Losses (23 %) and Targetted Losses in Foreseeable Future (15%)

Sl. No.	Voltage Level	Energy losses (%): Corresponding to present 23% Losses	Corresponding to Targetted 15% Losses	% Reduction Losses to be Achieved	Measures for Achieving the Reduction
1.	EHT (220/132/ 66 kV)	4.5	3.5	1.0	Normal development of EHT network, optimum reactive balance in grid, adoption of higher trans. Voltages, improved load despatch techniques etc.
2.	33 kV	4.0	2.75	1.25	(*i*) Reduction of line loading from 145 MW-kM to 105 MW-KM (*ii*) Reduction of transformation losses from 1% to 0.75 %. (*iii*) Improvement of P.F. from 0.8 to 0.85.
3.	11 kV	7.0	4.25	2.75	(*i*) Reduction of line loadings from 12 to 8.5 MW-KM for Weasel conductor and replacement of Squirrel by Weasel conductor. (*ii*) Reduction of transformation losses from 2% to 0.75% (*iii*) Improvement of P.F. from 0.75 to 0.8.
4.	L.T. (415 Volts)	7.5	4.50	3.0	(*i*) Reduction of Line loadings from 12.5 KW-KM to 7 KW-KM for Squirrel and from 14 KW-KM to 8 KW-KM for Weasel conductor. (*ii*) Reduction of Transformation losses from 2% to 1.75% (*iii*) P.F. improvement from 0.7 to 0.75.
	Total	23.0	15.0	8.0	

5.2 The above Table indicates that out of the total reduction of 7.0% (from 18.5% to 11.5%) in energy losses at 33 kV/11 kV/LT levels, more than 2% can be achieved by P.F. improvement and the balance of about 4.7% have to be achieved through 'Augmentation Works' involving strengthening of feeders and addition of new

TABLE IV

Estimation of Benefits due to P.F. Improvement and other Measures at 33 kV, 11 kV & L.T. Level for Reducing Losses from 23% to 15%

Sl. No.	*Voltage Level*	*Loss Reduction due to P.F Improvement (%)*	*Loss Reduction due to Other Measures (Augmentation works etc.)*	*Total Loss Reduction (%)*
1.	33 kV	0.46	0.79	1.25
2.	11 kV	0.84	1.91	2.75
3.	L.T.	1.00	2.0	3.0
4.	Total	2.30	4.70	7.0*

*Excluding 1% reduction to be achieved at EHT Transmission

substations in the Distribution System and taking steps to reduce transformation losses. The Table also indicates that substantial benefits (3% reduction) is to be derived by taking necessary corrective action at L.T. level, followed by action at 11 kV level (2.75%) reduction and 1.25% reduction at 33 kV level. Achieving this improvement would inter-alia involve the use of certain modern innovative equipments like switched capacitors, voltage boosters, automatic transformer disconnecting switches etc.

6. Energy Audit of a Typical Power System

6.1 In order to identify the areas where sizeable energy losses are taking place, it would be necessary to consider a typical power system and quantify the actual energy losses occurring in each separate section of the Transmission, sub-transmission and Distribution system due to the load flows in the respective sections. This would help us to fix up the order of priority for tackling the problem of reduction of T & D losses so that efforts are concentrated in those areas which would result in maximum benefits with minimum investment.

6.2 For this exercise (corresponding to the present 23% T & D losses), the typical T & D system comprising EHT system (220 kV & 132/66 kV), 33 kV, 11kV & L.T. considered is shown in Annexure I. It has been assumed that 100 Units are pumped at the 220 kV EHT bus and that the units lost due to transmission of the loads over the transmission/transformation system are 4.5%, 4.0%, 7.0% and 7.5% over the EHT, 33 kV, 11 kV & L.T. (vide Table I.) The sales at the bus-bars of different voltages have been assumed and is indicated in the schematic diagram. Sales pattern is based on present average All-India sales pattern. With this basic data, the losses occurring due to load flows through each section have been calculated and are indicated in the schematic diagram (Annexure-I). The calculations are presented in a tabular form in Table V. This Table indicates the losses in the system due to the various types of loads and helps in identifying the segments of the system where unduly high losses are taking place.

6.3 From Col. (8) of the Table V it is seen that maximum amount of losses are taking place in the L.T. sections (15.5%), followed by 10.5% in 11 kV, 5.2% in 33 kV and, 4.5% in the EHT Sections. Col. (9) of the Table indicates the %age contribution of each section

TABLE V

Sectionwise T & D Losses due to Loads at Different Voltage Buses Assuming Average A.I. Sales Pattern (Corresponding to 23% T & D Losses)

Sl. No.	*Voltage Receiving bus*	*No. of Units Pumped at Sending end*	*Units Lost due to Transmission of Load (Vide Table I)*	*No. of Units Reaching Receiving end bus*	*Units sold at Receiving end bus*	*Units Available for Transmission to next Lower Voltage bus*	*Section wise T&D Losses due to Load Flow* $\frac{(3)-(5)}{(3)} \times 100$	*%age Contribution to Total T & D Losses*
1	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*
1.	EHT (220, 132 & 66 kV)	100 (at EHT 220 kV bus)	4.5	9.55	19.0	76.5	4.5%	19.57
2.	33 kV	76.5 (at 132 kV bus)	4.0	72.5	6.0	66.5	5.2%	17.40
3.	11 kV	66.5	7.0	59.5	11.0	48.5	10.5%	30.43
4.	LT	48.4	7.5	41.0	41.0	Nil	15.5%	32.60
5.	Total	100 (at 220 kV bus)	23.0	—	77.0	—	—	100

Note:

It is seen from the above Table that 66.5 units are being pumped into the 11 kV bus and after allowing for sale of 11 units at this bus, net units pumped, into the distribution system is 55.5 units. Out of this 55.5 units, only 41 units are finally available for sale. Thus loss in distribution system works out to:

$$\frac{55.5 - 41}{55.5} \times 100 = 26\%.$$

towards total T & D Losses of 23%. It is seen that losses in the L.T. portion of the T & D system contribute to about 33% of the total T & D losses. This means that for supplying 1 unit at L.T. end, over 1.5 units have to be injected at the E.H.T. busbar (220 kV), as 0.5 units are lost in the transmission and transformation process during wheeling of the power. It also shows that apart from the 32.6% of the T & D losses occurring due to the L.T. loads, about 30.43% losses are accounted for due to 11 kV loads. Balance of about 37% losses are accountable towards E.H.T. & 33 kV loads.

6.4 A similar exercise has been carried out corresponding to the targetted total of 15% T & D losses assuming an anticipated sales pattern at the different voltage buses. For computing the units lost due to the load flows over the different sections of the system, the transmission/transformation losses have been assumed as per values arrived at in Table-II. The results are shown schematically in Annexure-II and are shown in a Tabular form in Table VI.

6.5 A comparison of the values of the sectionwise losses corresponding to total T & D losses of 23% under present conditions (Table V) with the corresponding sectionwise loss figures for targetted 15% total T & D losses (Table VI) leads us to the following conclusions:

(*i*) Since under the present system and loading conditions maximum quantum of losses (15.5%) are taking place in the L.T. section of the system, tackling the problem of L.T. level gets the top-most priority.

In order to reduce the total T & D losses to the targetted 15% level, Table VI indicates the L.T. section loss has to be brought down from present 15.5% to 8.9% level which is no doubt a formidable task and all efforts have to be made to achieve this.

(*ii*) The next area to be tackled in order of priority is the 11 kV section of the system where the sectionwise loss has to be reduced from 10.5% to 6.3%.

(*iii*) At 33 kV level, a comparison of the sectionwise losses shows that the loss requires to be brought down from 5.2% to 3.6%.

(*iv*) At EHT (220/132/66) level, the sectionwise losses are required to be reduced from present 4.5% to 3.5% level. Here it is expected that the normal development of the EHT transmission network to handle the additional generation that would become available in the system will take care of this reduction of 1%.

7. Additional Fund Requirements for T & D in VIIth Plan for Reduction of Losses by 4% (from 23 % to 19%)

7.1 The total capital outlay for the Power Sector during the VII Plan is Rs. 34,000 crores, out of which Rs. 22,000 crores has been allocated towards Generation and Rs. 12,000 crores for T & D comprising Rs. 6,000 crores for Transmission and Rs. 6,000 crores for Distribution. Further, VII Plan envisages an additional installed capacity of 22,245 MW. With the above basic data it would be interesting to make a hypothetical study for making a rough estimation of the fund requirements for reducing the T & D losses from the present level of 23% to say 19% by the end of VII Plan, assuming that the entire 4% reduction is to be achieved at the 33 kV/LT system level.

7.2 A very rough estimation of the probable fund requirements in addition to Rs. 12,000 crores already provided in VII Plan for T & D for the above purpose has been made-vide Appendix I. According to this

TABLE VI

Sectionwise T & D Losses due to Loads at Different Voltage Buses Assuming AI Sales Pattern (Corresponding to 15% T & D Losses)

Sl. No.	*Voltage Receiving bus*	*No. of Units Pumped at Sending end*	*Units Lost due to Transmission of Load (Vide Table II)*	*No. of Units Reaching Receiving end bus*	*Units sold at Receiving end bus*	*Units Available for Transmission to next Lower Voltage bus*	*Sectionwise T&D Losses due to Load Flow $\frac{(3)-(5)}{(3)} \times 100$*	*%age Contribution to Total T&D Losses*
1	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*
1.	EHT (220,132 & 66 kV)	100 (at EHT 220 kV bus)	3.50	96.5	20.5	76.0	3.5%	22.58
2.	33 kV	76.0	2.75	73.25	6.0	67.25	3.6%	17.74
3.	11 kV	67.25	4.25	63.00	12.5	50.50	6.3%	27.42
4.	LT	50.50	4.50	46.00	46.0	Nil	8.9%	30.00
5.	Total	100 (at 220 kV bus)	15.00	—	85.0	—	—	100

Note:

It is seen that 67.25 units are being pumped into the 11 kV bus and after allowing for sale of 12.5 units at this bus, net units pumped into the distribution system is 54.75 units. Out of this 54.75 units finally 46 units are available for sale. Thus loss in distribution system works out to:

$$\frac{54.75-46}{54.75} \times 100 = 15.98\%$$

estimate for effecting the entire intended reduction of 4% in the Distribution system alone, an additional investment of about Rs. 1,500 crores may be required during the VII Plan. Thus the overall position regarding VII Plan capital outlay on the T & D Sector would be as follows:

Sl. No.	Item	Amount Already Provided in VII Plan Rs. Crores	Estimated additional Amount reqd. for 4% Reduction in T & D Losses Rs. Crores	Total Rs. Crores	Losses
1.	Transmission	6,000	—	6,000	4.5%
2.	Distribution	6,000	1,500	7,500	14.5%
3.	Total T & D	12,000	1,500	13,500	19%

8. Fund Requirements in VIII Plan on 'Distribution' for Reducing T & D Losses from 19% to 15% Level at end of VIII Plan

8.1 Assuming that it has been possible to attain a T & D loss level of 19% by VII Plan end, another exercise has been carried out to make a rough assessment of fund requirements for reducing the losses further to 15% level by VIII Plan end-vide Appendix II. This exercise has been made basically to estimate the fund requirements in VIII Plan to achieve a loss level of 11% (as against 14.5% at VII Plan end) in the Distribution system, assuming that the investment on Transmission works made on the pattern of earlier Plans would be adequate to contain the transmission losses at 4% level (as against 4.5% at VII Plan end). Presuming that following the pattern of investments on T & D in the earlier Plans only Rs. 20,000 crores (comprising Rs. 10,000 crores for Transmission and another Rs. 10,000 crores for Distribution) is provided for in VIII Plan for these works, it is estimated that an additional sum of 5,000 crores should be made available for achieving 15% loss level. Thus the picture regarding investments in T & D during VIII Plan for achieving the target of 15% losses would be as below:

Sl. No.	Item	Amount Expected to be Provided in VIII Plan Following Pattern of earlier Plans Rs. Crores	Estimated Additional Amount Required for 4% Reduction on VII Plan base of 19% Rs. Crores	Total Rs. Crores	Losses
1.	Transmission	10,000	—	10,000	4%
2.	Distribution	10,000	5,000	15,000	11%
3.	Total (T & D)	20,000	5,000	25,000	15%

9. Cost Benefit Analysis

9.1 It is felt that there is lack of proper appreciation on the part of the concerned authorities regarding the relative importance to be attached to the problem of excessive T & D losses vis-a-vis expansion of generating capacities. On the average, in the various Five Year Plans the allotted funds for T & D have been of the order of 40-50% of the funds earmarked for Generation, whereas for the development of a well balanced system it is considered desirable to have investments in Generation and T & D Sectors in the ratio of 1 : 1. The prevailing pattern of lop-sided investments in the power sector laying higher stress on expansion of generating capacities at the cost of T & D augmentation has resulted in depriving the associated transmission and distribution facilities of the necessary reinforcements required to cope with the increased power availability to be distributed to a larger number of consumers. This somewhat short-sighted policy apart from affecting the quality of power supply to the consumers both in terms of reliability and delivery of power to them at proper voltage, is also causing the power utilities to lose crores of rupees, year after year, because of the revenue they are losing on account of the high T & D losses. These losses could be reduced to a great extent provided the required funds were made available to them specifically for this purpose.

9.2 Besides the fact that in view of the global energy crisis such waste of precious energy is to be avoided at all costs even viewed from a purely commercial angle investments on reduction of T & D losses offers a very profitable proposition. It is assessed that if we were able to reduce the T & D losses even by 1% only during the Seventh Plan, this would be equivalent to setting up a power station of about 600 MW capacity (Vide Appendix-III). A thermal station of this capacity, at present day price level would cost around Rs. 600 crores, whereas 1% saving in T & D losses by power factor improvement would cost only a fraction of this amount (around Rs. 100 crores). Further, it is estimated that 1% saving in T & D losses in the Seventh Plan would enable the power utilities to earn an additional revenue of about Rs. 200 crores per annum (vide Appendix-III). Thus viewed from any angle, saving in T & D Losses is a very attractive proposition. It would therefore be in the national interest to put in concerted efforts to reduce T & D losses, and necessary finances should be made available to the power utilities for this purpose.

9.3 There is very strong case therefore for providing

an estimated additional amount of Rs. 1,500 crores in the VII Plan for achieving a T & D loss level of 19% (as against present 23% level). For VIII Plan also adequate provision should be made for T & D in order to bring down the losses further from 19% to 15%. It has been roughly estimated that, at the present level of prices, an additional amount of about Rs. 5,000 crores (over and above Rs. 20,000 crores likely to be provided in Eighth Plan if the pattern of investments on T & D in earlier Plans were continued to be followed) would have to be invested for this purpose. The benefits that would accrue due to 4% reduction in T & D losses in VII Plan and another 4% in VIII Plan is indicated in Appendix IV and the results are summarised in the following Table:

one to conclude that in Indian Power systems, the break-even point from economic considerations for T & D loss reduction might be around 14-15%. Thus viewed from purely a commercial angle, the proposition of reducing T & D losses below 14-15% level is likely to prove more costly than the alternative of installing additional generating capacity along with associated T & D facilities.

10. Conclusion

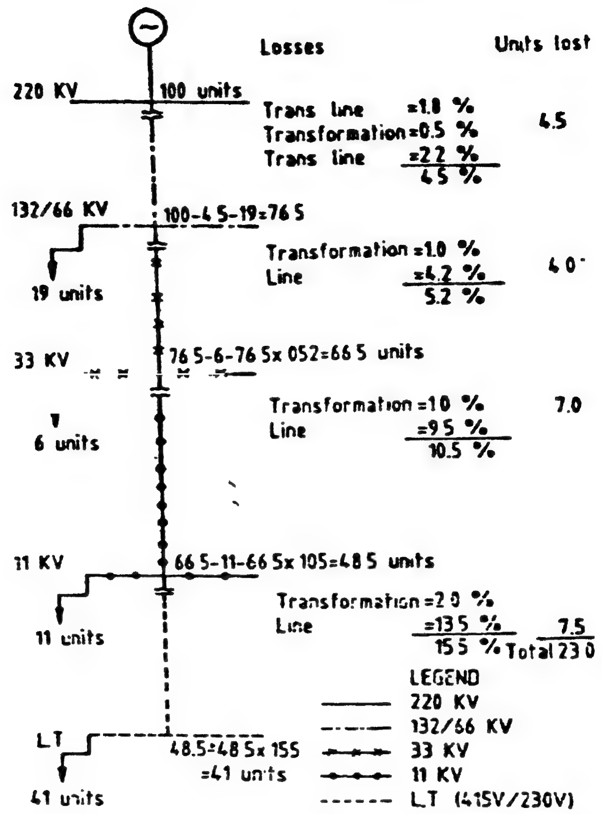
It is suggested therefore that the main thrust in the mid-term appraisal of the Seventh Plan provisions as also the VIII Plan should be towards reduction of Transmission and Distribution losses. According to the above estimates a special provision of the order of Rs. 6,500 crores comprising Rs. 1,500 crores during Seventh Plan and another Rs. 5,000 crores for Eighth Plan earmarked exclusively for 'System Improvement and Augmentation Works' spread over a period of about seven years is called for. The Central Government should create, on a priority basis, a special fund for this purpose outside the State Plan funds on the lines of the Union Ministry of Energy's scheme for modernisation and renovation of power plants. The State Electricity Boards, in their turn, should be ready with the necessary 'System Improvement' schemes worth about Rs. 2000 crores during VII Plan and another Rs. 5,000 crores worth schemes for implementation during the Eighth Plan spread over a period of about seven years. Each of the SEBs should also have a list of the schemes to be taken up in order of priority from the angle of cost-effectiveness, so as to realise the most optimal benefits within the constraints of fund availability and their own capabilities of implementing the schemes.

			Alternative-I	*Alternative-II*				
Sl. No.	*Period*	*Extra Power Availability due to 4% Reduction in T & D Losses (MW)*	*Additonal Amount reqd. for T & D Works for Getting Extra MW in (Col. (3) (Rs. Crores)*	*Cost of Thermal gen. unit of Capacity at Col. (3) @ Rs. 10,000 per kW (Rs. Crores)*	*Estimated Cost of T & D Associated with the Gen. unit (Rs. Crores)*	*Total of Alt. II (5) + (6) (Rs. Crores)*	*Cost per MW (Alt.-I) (Rs. Crores)*	*Cost per MW (Alt.-II)*
1	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*
1.	VII Plan	2,300	1,500	2,300	1,600	3,900	0.65	1.70
2.	VIII Plan	3,600	5,000	3,600	2,500	6,100	1.39	1.69

9.4 It will be seen from the above Table that reduction of T & D losses by 4% in VII Plan and another 4% in VIII Plan would result approximately in availability of extra 2300 MW and 3600 MW in the respective Plan periods. Further, the Table also indicates that from a purely commercial angle, in the Seventh Plan it is a profitable proposition to avail of extra 2000 MW by T & D loss reduction method (cost Rs. 65 lakhs/MW) compared to the alternative of installing an equivalent 2300 MW thermal generating capacity along with associated T & D system at a much higher cost of the order of Rs. 170 lakhs/MW. However, in the VIII Plan, for realising the benefit of availability of extra 3600 MW (that would accrue due to T & D loss reduction from 19% in VII Plan to 15% in VIII Plan) the difference in the expenditure involved per MW in both the alternatives narrows down considerably-only Rs. 30 lakhs/MW (i.e. Rs. 169 lakhs/MW—Rs. 139 lakhs/MW) compared to the corresponding difference of about Rs. 105 lakh/MW in the VII Plan with 19% T & D losses. This would lead

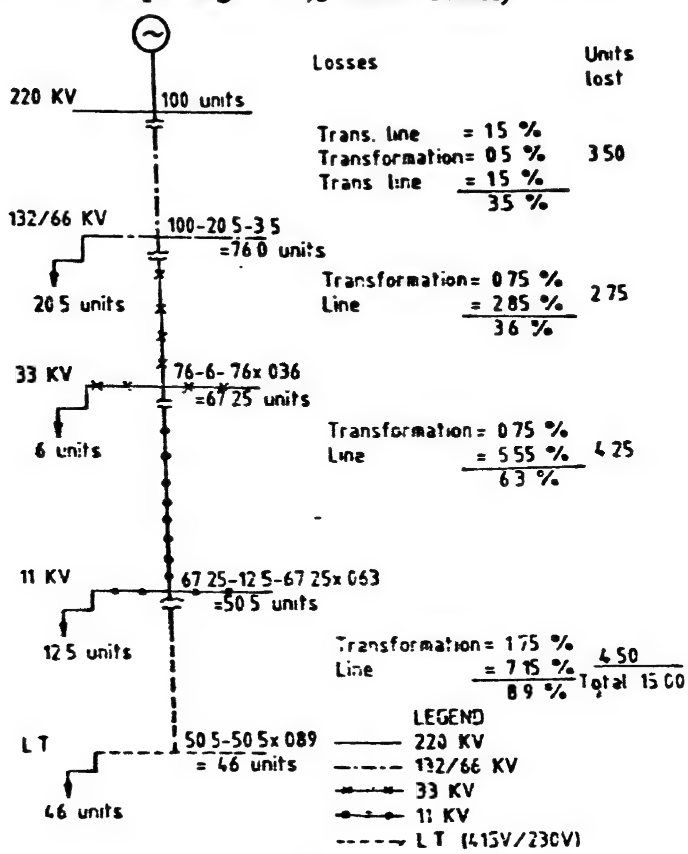
ANNEXURE—I

Section wise T & D Losses due to Loads at Different Voltage Buses Assuming A.I. Sales Pattern (For 23% T & D Losses)



ANNEXURE—II

Section wise T & D Losses due to Loads at Different Voltage Buses Assuming A.I. Sales Pattern (Corresponding to 15% T & D Losses)



APPENDIX—I

Rough Assessment of Additional Fund Requirements in VII Plan for Reducing T&D Losses by 4% (from Present 23% to 19%)

Basic Data

(*i*) Total investment on 'Distribution' till VI Plan end. = Rs. 5,400 crores

(*ii*) Provision for 'Distribution' in VII Plan. = Rs. 6,000 crores

(*iii*) Value of Pre-VII Plan investment on 'Distribution' at present-day price level = Rs. 5,400 × 3 = Rs. 16,200 crores

Assumptions

(*i*) T&D loss at VI Plan end = 23% (comprising 4.5% Transmission and 18.5% Distribution losses).

(*ii*) T&D loss remains at 23% level with present provision of Rs. 6,000 crores for VII Plan 'Distribution' as this amount would be just adequate to cope with the additional generating capacity.

(*iii*) T&D loss at VII Plan end. = 19% (comprising 4.5% Transmission & 14.5% Distribution losses)

Calculations

From Table-IV it is seen that it is feasible to reduce the Distribution losses by 2.3% by P.F. improvement of 0.7 to 0.75 at LT, 0.75 to 0.8 at 11 kV and 0.8 to 0.85 at 33 kV. In order to achieve the over-all reduction of 4%, let us assume that 2.3% reduction is to be achieved through P.F. improvement and 1.7% by augmentation works. Thus by P.F. improvement distribution losses reduced to 18.5% − 2.3% = 16.2% By 'System Augmentation Works', the losses to be further reduced to 16.2% − 1.7% = 14.5%. Now let us estimate the fund requirements for the above two tasks.

Additional Funds for P.F. Improvement in Seventh Plan

Assuming that the peak demand to be met in Seventh Plan is expected to be about 49,000 MW, the position regarding fund requirements in Seventh Plan for achieving a loss reduction of 2.3% by P.F. improvement is shown below:

Sl. No.	*kV*	*Assumed Average Load (MW)*	*P.F. Correction required*	*MVAR required*	*Cost @ Rs. 3 lakhs per MVAR*
1.	33	16,000	0.8-0.85	2080	
2.	11	12,000	0.75-0.8	2880	5800 MVAR × Rs. 3 lakhs = 17,400 lakhs
3.	LT	7,000	0.7-0.75	840	Rs. 175 crores (say)

Additional Funds for Augmentation Works in Seventh Plan

We have to now assess the fund requirements for system Augmentation Works from 16.2% to 14.5%.

Assuming that by doubling the investment on these works, losses would become 1/4th of the original losses, it is seen in order to bring down the losses from 16.2% to 14.5%, the multiplying factor (×) by which the original investment has to be multiplied works out to

$$X = \sqrt{\frac{16.2}{14.5}} = 1.057$$

Thus, the additional funds required (over and above present value of pre-VII Plan investment viz. Rs. 16,200 crores and VII Plan provision of Rs. 6,000 crores) would be:

Additional Investment for Augmentation works = 0.057 × (16,200 + 6,000)
= Rs. 1,265 crores
Say Rs. 1,300 crores

Total Additional Fund Requirements

	Rs. crores
(*i*) Additional Fund for Augmentation works for reducing losses by 1.7%	1,300
(*ii*) Funds for P.F. improvement for reducing losses by 2.3%	175
Total :	1,475
Say :	Rs, 1,500 crores

Rough Assessment of Investments on T and D in VIII Plan for Reducing Losses from 19% to 15% (Reduction 4%)

Basic Data

Investment on 'Distribution'

	Rs. crores	
Till VI Plan	16,200	(Present cost)
In VII Plan (Original)	6,000	(Actual provision)
In VII Plan (Additional)	1,500	(Computed)
	23,700	
In VIII Plan (original)	10,000*	
	33,700	

Investment on Transmission

In VIII Plan 10,000*
*Assumed on basis of past investment pattern.

Assumptions

(*i*) T and D loss at VII Plan end = 19% (Comprising: Transmission: 4.5% & Distribution: 14.5%)

(*ii*) Provision of Rs. 10,000 crores* helps in maintaining T and D loss at 19% i.e., this investment is just adequate to cope with the additional generation availability in VIII Plan.

(*iii*) T and D loss at VIII Plan end = 15% (Comprising: 4% Transmission losses and 11% Distribution losses)

(*iv*) Reduction of distribution losses) from 14.5% to 11% achieved in two steps:

(a) 1% by P.F. correction (11 kV: 0.8 to 0.85 and LT: 0.75 to 0.80) = 14.5% − 1% = 13.5%

(b) Balance 2.5% by Augmentation works: = 13.5% − 2.5% = 11%

Calculations

Fund Requirements for P.F. Improvement (VIII Plan)
Assumed VIII Plan Peak Demand = 78,500 MW

Sl. No.	kV	Assumed Average load MW	P.F. Correction range	MVAR Required	Cost @ Rs. 3 lakhs per MVAR
1.	33	25,600	0.85	—	—
2.	11	19,000	0.8 to 0.85	0.13×19,100 = 2460	4,000 MVAR @ Rs. 3 lakhs/MVA = Rs. 1,2000 lakhs = Rs. 120 crores
3.	LT	11,000	0.75 to 0.8	0.14×11,000 = 1540	
				Total : 4,000	

Funds for Augmentation Works

(*i*) Required Additional Funds

$= \sqrt{\frac{13.5}{11}} - 1 \times$ Rs. (23,700 + 10,000) crores
= 0.108×33,700
= Rs. 3,733 crores
= Rs. 3,800 crores (say)

(*ii*) Investment in VIII Plan for P.F. improvement
As worked out separately,
Requirement = Rs. 120 crores.

Total Additional Fund Requirement in VIII Plan (additional to Rs. 10,000 crores assumed to be made in VIII plan based on past pattern)

	Rs. Crores
For Distribution Augmentation works	3,800
For P.F. Improvement	120
	4,920

Say, Rs. 5,000 crores (Additional)

APPENDIX—III

Rough Assessment of Impact of 1% Reduction in T and D Losses in Seventh Plan

(*i*) *Generating Capacity Equivalent to 1% saving in Energy*

Estimated annual energy consumption at end of VII Plan = 250,000 MkWh

1% saving in energy $= 25\times10^2$ MkWh $= 25\times10^8$ kWh

Assuming a PLF of 55% and auxiliary consumption @ 10%, the installed capacity required to generate 1% energy saved i.e., 25×10^8 kWh is:

$$\text{MW capacity} = \frac{25\times10^8 \text{ kWh}}{365\times24\times0.55\times10^3} = 524 \text{ MW}$$

Allowing for 10% auxiliary consumption = 52 MW

∴ Total capacity = 576 MW

Say 600 MW

Cost of thermal generating of 600 MW @ Rs. 10,000 per kW Rs. *600 crores*

(*ii*) Estimate of extra revenue to be earned by SEBs because of 1% *saving in energy*.

Extra revenue earned by SEBs by selling 25×10^8 kWh energy (saved by 1% reduction in T and D losses @75 p/unit)

$= 25\times10^8\times0.75 = 188$ crores.

Say = Rs. 200 crores per annum.

APPENDIX—IV

Rough Assessment of Impact of 4% Reduction in T and D Losses in VII and another 4% in VIII Plan

	VII Plan	*VIII Plan*
1. Estimated energy consumption	250,000 MkWh	390,000 MKWh
2. 4% saving in energy	100×10^8 kWh	156×10^8 KWh
3. Assuming 55% PLF, 10% Auxiliary consumption, installed generating capacity required	2,300 MW	3,600 MW
4. Cost of thermal generating capacity @Rs. 10,000 per kW	Rs. 2,300 crores	Rs. 3,600 crores

PROBLEMS OF INTEGRATED GRID OPERATION

AND THEIR COMPREHENSIVE SOLUTION

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For Presentation at the Training Programme for the "Planning for the Power Sector" being held at Hotel Mughal Sheraton, Agra, from 9-13 December, 1991.

PROBLEMS OF INTEGRATED GRID OPERATION AND THEIR COMPREHENSIVE SOLUTION THROUGH RESTRUCTURING OF INTER-UTILITY TARIFF

MAJOR PROBLEMS /SYMPTOMS

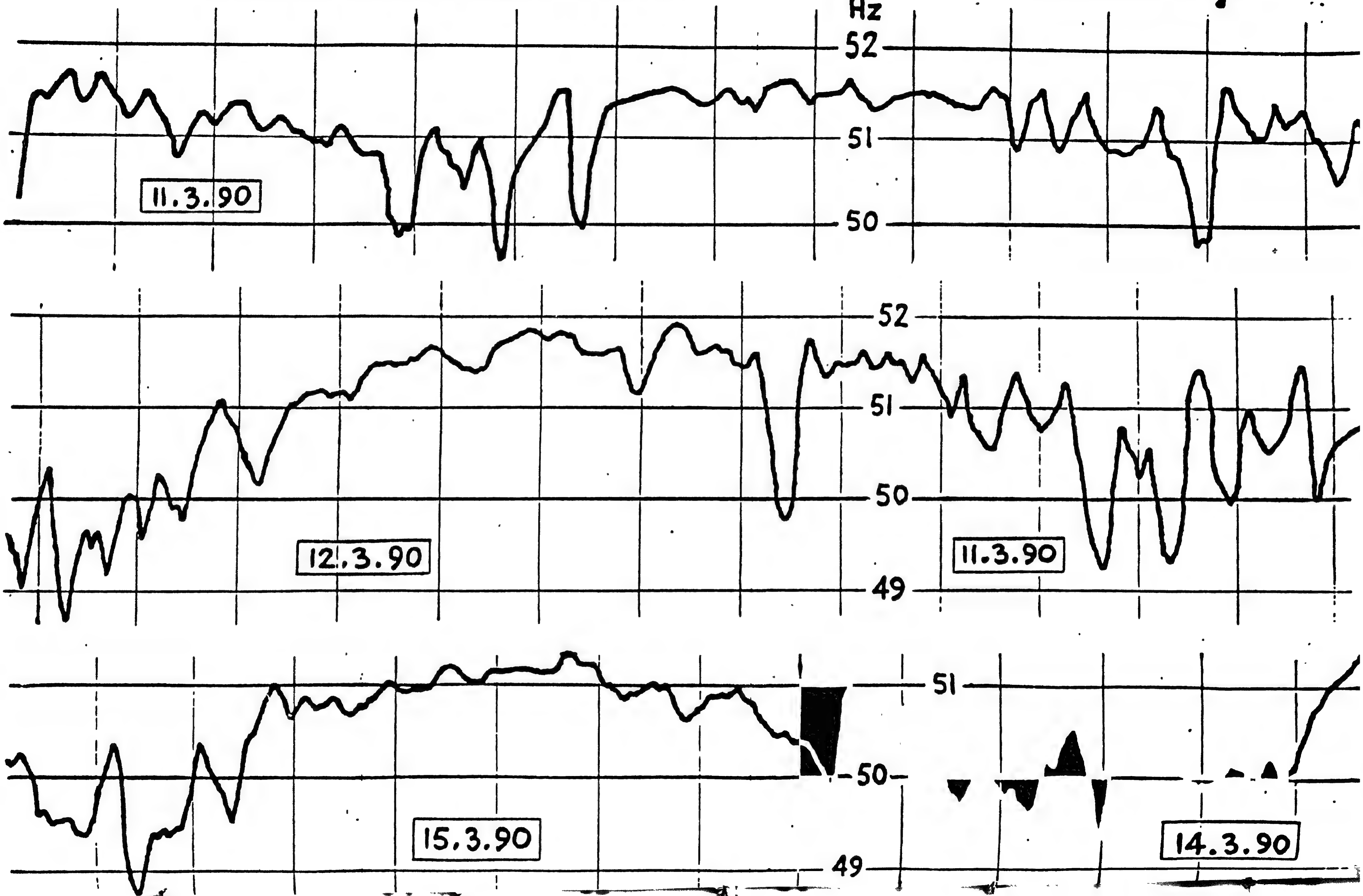
- Wide frequency fluctuations/excursions.
- Unchecked overdrawals by SEBs
- Grid indiscipline
- Non-optimum operation
- Frequent grid collapses
- Abnormal voltage profiles
- Perpetual commercial disputes

Situation is deteriorating further due to :

- Inadequacy and poor availability of generating capacity
- Consequent lack of spinning reserve during peak-load hours
- Inadequacies in transmission and distribution systems
- Inadequate VAR compensation
- Lack of Load - dispatch and communication facilities
- Shortage of resources to overcome the above quickly

TYPICAL FREQUENCY PLOTS

Northern Region



FREQUENCY RESTRICTIONS FOR STEAM TURBINES

AS PER I.E.C. SPECIFICATION

49.0 - 50.5 Hz	-	No restriction
Above 50.5 Hz	-	No mention (not foreseen)
Below 49.0 Hz	-	Permissible during emergency; duration as per agreement between manufacturer and purchaser

KWU, ANSALDO

47.5 - 51.5 Hz	-	No restriction

BROWN BOVERI

48.5 - 51.5 Hz	-	No restriction
48.0 - 48.5 Hz	-	20 min at a time, and 2 hours in a year
47.5 - 48.0 Hz	-	10 min at a time, and 1 hour in a year
Below 47.5 Hz	-	10 sec at a time

U.S.S.R. DESIGN

49.0 - 50.5 Hz	-	No restriction
50.5 - 51.0 Hz	-	3 min at a time, and 500 min in whole life
48.0 - 49.0 Hz	-	-do-
47.0 - 48.0 Hz	-	1 min at a time, and 180 min in whole life
46.0 - 47.0 Hz	-	10 sec at a time, and 30 min in whole life

ADVERSE EFFECTS OF FREQUENCY FLUCTUATIONS ON POWER PLANTS

1) Resonance of last stage blades of steam turbines and gas turbines, and consequent break downs

2) Sudden tripping of gas turbines on high or low frequency reduces their life (by about one month per full-load trip)

3) Fall of output of plant auxiliaries due to slowing down of motors on fall of frequency, and consequent reduction of generating capacity

4) Fall in steam and gas turbines' output (MW) capability on fall in frequency (2-2½% per cycle), due to reduced speed

5) Overloading of auxiliary motors during high frequency conditions

6) Mal-operation of U.P.S. and D.A.S. when frequency goes beyond specified range.

7) Turbine governors have to be made inoperative, and generation control becomes totally adhoc and disorderly

8) Serious effects on plants' life due to thermal shocks caused by disorderly load changes

9) Serious risk of dangerous over-speeding of turbine-generators on load throw-off, when normal governor action has been suppressed.

10) Over-fluxing of generators and transformers during low-frequency conditions

ADVERSE EFFECTS OF FREQUENCY FLUCTUATIONS ON POWER SYSTEM'S OPERATION

1) Frequency cannot be used as a signal for generation control, and load-frequency control cannot work.

2) Economy dispatch cannot be applied and resources cannot be used optimally, through simple means.

3) A real system emergency cannot be detected in time, and automatic load-shedding cannot be applied in advance. System contingencies, which could otherwise be controlled by timely automatic and|or manual load-shedding, also lead to grid collapses 2-3 times every year.

4) Over-heating of shunt reactors

5) Back-to-back H.V.D.C. becomes mandatory for inter-Regional connections.

6) H.V.D.C. and S.V.C. control and harmonics' suppression become complicated and costlier.

FREQUENCY FLUCTUATION RELATED CONTRIBUTORY FACTORS WHICH LEAD TO GRID COLLAPSES

1) Spinning reserve made inoperative due to suppression of governor action on many turbines

2) Lack of timely load-shedding, as it cannot be initiated till the frequency goes too low

3) Low-frequency condition prior to a system contingency leaves no cushion|time for recovery measures to take effect.

ADVERSE EFFECTS OF FREQUENCY EXCURSIONS FOR CONSUMERS

1) Loss of industrial production due to slowing down of motors when frequency is low

2) Over loading of motors when frequency is high

3) Computers mal-operate or stop working

4) Synchronous clocks start drifting

5) Captive Power Plants paralleled with the grid suffer in similar fashion

6) Manufacturing process in paper mills, textile mills etc gets affected.

REASONS FOR FREQUENCY FLUCTUATIONS/EXCURSIONS

(A) TECHNICAL

Most generating units are operating on constant-load mode, with turbine governors made virtually inoperative. As such, they do not participate in frequency control, and frequency fluctuations increase.

WHY ARE WE OPERATING OUR PLANTS LIKE THIS ?

Because the present frequency fluctuations are so wide and wild that any generating unit left on normal free-governor (speed-load control) mode would perpetually suffer violent load changes, and consequently have serious operational problems and premature equipment failures.

So we are being forced into a man-made spiral.

(B) COMMERCIAL

The present inter-State and Central stations' power tariffs

- do not discourage overdrawals by SEBs, which the latter could avoid by carrying out load management in their states.

- do not encourage SEBs to run up their own higher cost generation (Diesel generators, Gas turbines etc.) for assisting the system in contingencies.

- do not induce power plant operators to back down during off-peak hours. (This applies to both SEBs' and Central stations)

- do not provide any financial compensation to any party for over-stressing its power plants for assisting the system during contingencies.

(C) OTHER REASONS

1) No coordinated directive to power plant operators to regulate the grid frequency

2) Misconcept that frequency control is REB's or Load dispatch centre's responsibility

3) Misconcept that base-load operation means constant-load mode, making the turbine governors inoperative

4) Directives to SEBs to meet their own loads and load changes, by regulating their own generation, are not complied with

5) External pressures for not disconnecting any consumers; so, little effective load management

6) No serious attempt to identify over-drawals, and penalise or levy a surcharge for them

7) PLF-linked bonus schemes, which encourage plant operators not to back down, and to disregard instructions of Load despatch centres

8) Non-realisation of the gravity of the situation, and lack of collective will to solve the problem

WE HAVE UNWITTINGLY DONE EVERYTHING THAT GOES TO ENHANCE THE FREQUENCY FLUCTUATIONS

PAST EFFORTS limited to :

- Discussions and seminars, generally blaming peripheral factors for the present situation and concluding that no improvements can be brought about

- Commercial issues seen in isolation

THE UTILITIES' OPTIONS

1) They can prevent financial loss by keeping their plants in operation at available capability irrespective of system frequency.

   Result : Loss of customers' goodwill, and frequency-related damages to generating units.

2) They can earn their customer's goodwill by operating their plants as per grid requirements.

   Result : Load fluctuations and resulting damages to their power plants, and financial loss.

3) They can save their power plants from damages due to load and frequency fluctuations only by shutting down the generating units.

   Result : Financial loss, loss of customers' goodwill, and reduction of plant life due to repeated trippings.

PRIMARY CAUSE FOR THIS DILEMMA :

FAULTY INTER-UTILITY TARIFF STRUCTURE

THE REMEDY

1) ALL generating units throughout the Regional grids have to be changed over to free-governor action. This will stabilise the grid frequency and evenly distribute system load changes on all generating units.

2) The stabilised grid frequency can then be regulated according to total system load, and used as the load dispatch signal for system-wide generation control and load management, through REB's standing instructions aimed at merit order operation of the whole system.

3) PLF has to be replaced by Plant Availability Factor for judging plants' performance and for determining personnel's bonus.

4) Inter-State and Central stations' tariff structure has to be changed such that

   - no utility suffers financially in case it backs down its generation during a generation-surplus situation.

   - no utility suffers financially when it runs its diesel-generators and gas turbines to support the grid during a generation-deficit situation.

   - there is an automatic enhancement of charges for over-drawals during a generation-deficit situation, and

   - There is a concession for drawing more power during generation-surplus situation.

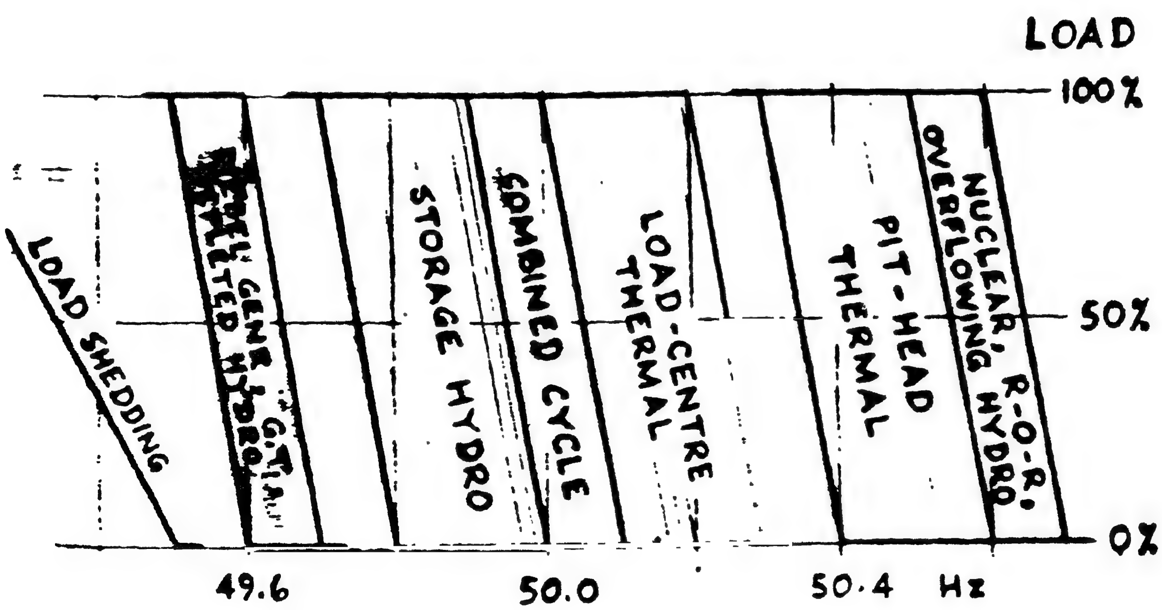
ALL THESE HAVE GOT TO BE DONE TOGETHER, AND WITHOUT FURTHER DELAY.

- Inter-State and Central stations' tariffs
- Principles of Economy dispatch
- Operating instructions and guidelines
- Technical requirements of frequency stability
- Power plants' health and life
- Personnel's interests
- Financial interests of SEBs, NTPC, NPTC, etc.

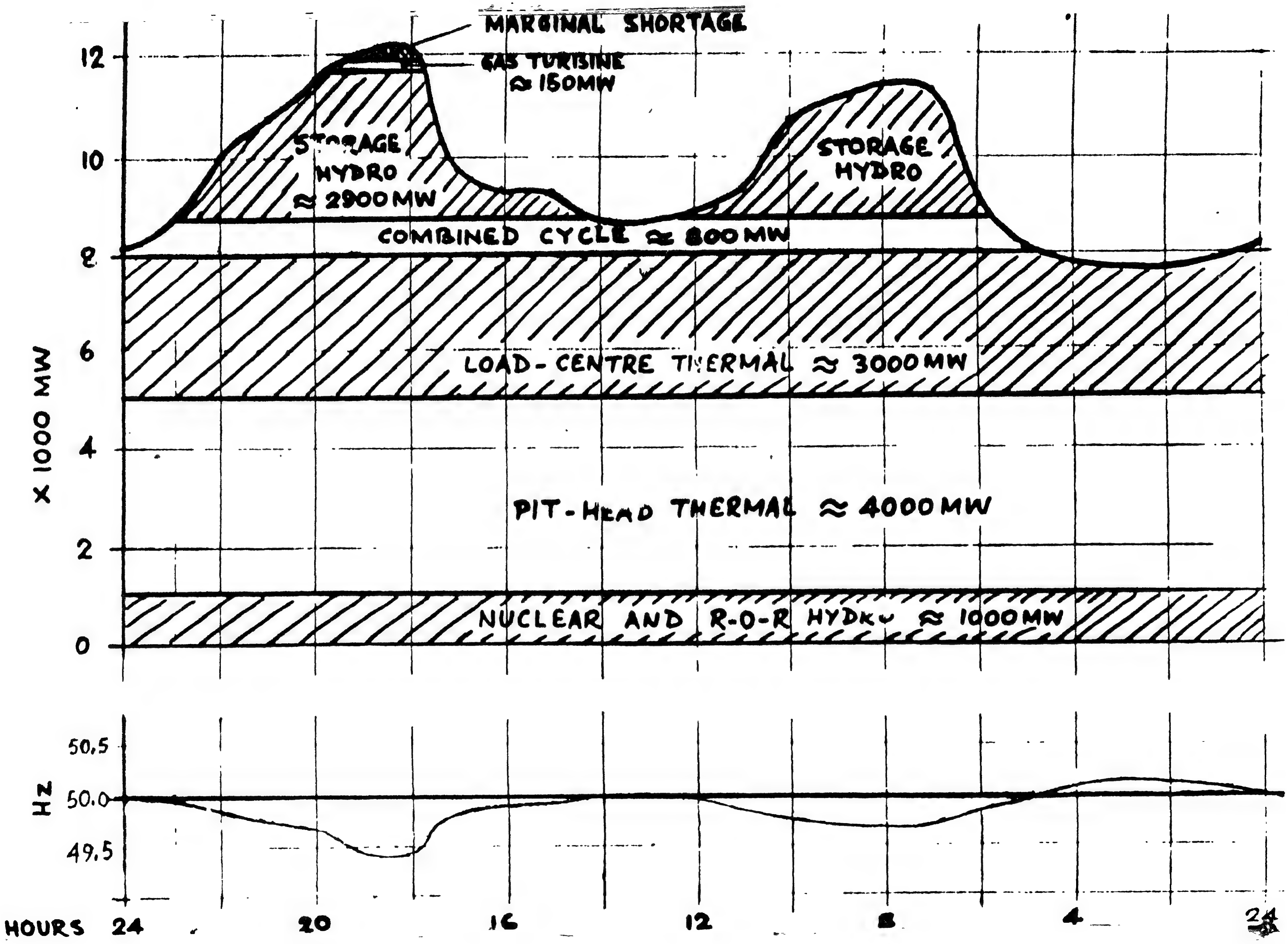
SHOULD NOT WORK AGAINST EACH OTHER

INCREMENTAL COST must appear as a distinct factor in inter-State and Central stations' tariff structure.

TYPICAL STANDING LOAD DISPATCH INSTRUCTION



CRITERION : MERIT ORDER ACCORDING TO INCREMENTAL COST OF GENERATION


MARGINAL SHORTAGE
GAS TURBINE ≈ 150MW
STORAGE HYDRO ≈ 2900MW
STORAGE HYDRO
COMBINED CYCLE ≈ 800MW
LOAD-CENTRE THERMAL ≈ 3000MW
PIT-HEAD THERMAL ≈ 4000MW
NUCLEAR AND R-O-R HYDRO ≈ 1000MW
X 1000 MW
12
10
8
6
4
2
0
Hz
50,5
50.0
49,5
HOURS
24
20
16
12
8
4
24

COMPUTATION OF PLANT AVAILABILITY FACTOR

FOR NUCLEAR POWER PLANTS :

$$\frac{\text{Energy (MWh) enerated while frequency} < 50.5\ \text{Hz}}{\text{Plant capacity (MW)} \times \text{Hours for which freq} < 50.5\ \text{Hz}}$$

FOR PIT-HEAD THERMAL POWER PLANTS :

$$\frac{\text{Energy (MWh) enerated while frequency} < 50.3\ \text{Hz}}{\text{Plant capacity (MW)} \times \text{Hours for which freq} < 50.3\ \text{Hz}}$$

FOR LOAD-CENTRE THERMAL POWER PLANTS :

$$\frac{\text{Energy (MWh) generated while frequency} < 50.0\ \text{Hz}}{\text{Plant capacity (MW)} \times \text{Hours for which freq} < 50.0\ \text{Hz}}$$

FOR COMBINED CYCLE POWER PLANTS :

$$\frac{\text{Energy (MWh) generated while frequency} < 49.9\ \text{Hz}}{\text{Plant capacity (MW)} \times \text{Hours for which freq} < 49.9\ \text{Hz}}$$

Basically, PAF is nothing but PLF for the period the concerned power plant should operate at its full available capacity.

Backing down in off-peak hours will not result in lowering of PAF and reduction of incentives.

The ratio "Actual PAF|Availability Norm" would be a direct indicator of the plant's performance.

Suggested INTER-STATE TARIFF for power interchange without a permanent commitment

1) Average of incremental costs of load-centre thermal plants of the concerned States, while the frequency is normal (not below 49.7 Hz but below 50.3 Hz)

2) Incremental cost of pit-head thermal plants of the Region, while frequency is high (50.3 Hz or higher)

3) Incremental cost of diesel-generators, while the frequency is low (below 49.7 Hz)

4) Fixed costs to be totally neglected. Only a simple paisa per kWh charge as above, on reciprocal basis.

WHY SHOULD THE TARIFF BE BASED ON FREQUENCY ?

1) Grid frequency and its trend are continuous indicators of generation - load balance. A high-frequency invariably means generation - surplus situation in which even pit-head stations may have to back down. A low-frequency condition invariably means a generation-deficit, in which diesel-generator|gas turbine support may be required.

2) Due to the above, the proposed frequency-linked tariff structure would be incremental cost-based under all conditions, which is ideal.

3) At any given time, the frequency is same all over the system, and can be measured precisely with ease anywhere.

Suggested TARIFF STRUCTURE FOR COMMITTED POWER SUPPLY FROM CENTRAL POWER PLANTS of any type : Thermal, Nuclear, Hydro, Combined cycle

THREE - PART TARIFF

(a) Fixed cost of the plant in proportion to the allocated share* of SEB, Rs|day (pre-fixed)

(b) Fuel cost for the daily power-drawal pattern which the SEB proposes as the base for this purpose, Rs|day (pre-fixed)

(c) Adjustment for deviations from the base power drawal pattern, paisa|kWh

- Average incremental cost of load-centre thermal plants of concerned States, while the frequency is normal (not below 49.7 Hz but below 50.3 Hz)

- Incremental cost of pit-head thermal plants, while the frequency is high (50.3 Hz or higher)

- Incremental cost of diesel-generators, while the frequency is low (below 49.7 Hz)

Total charges = (a) + (b) ± (c)

*as per Gadgil Formula, or the percentage of plant capacity a beneficiary would like to book for himself by agreeing to pay its fixed cost.

Maximum MW in base power drawal pattern shall be limited to : (Total generator MCR - Auxiliary consumption and losses) x Availability norm x SEB's % share.

BENEFITS FOR GENERATING AGENCIES

1) A reasonable return on their investments

2) Full reimbursement of all reasonable O & M expenditure and fuel cost

3) A bonus for higher plant availability, better heat rate etc

4) No financial loss if backing down is required in off-peak hours

5) No disputes with customers (SEBs) in accounting and billing, as dumped power and overdrawals are separately measured and charged

6) Faster billing and realisation of dues

7) Stable and safer operation of generating units, with minimised frequency and load fluctuations and fewer unit trip outs

8) Reduced thermal shocks, and consequent increase in plant life

9) Pit-head thermal plants would automatically operate as base-load plants

10) No conflicts with personnel's interests, as incentives are not affected by backing down

COMMON BENEFITS FOR ALL

1) Operation as per Economy dispatch principles, and best utilisation of resources : Overall economy

2) Reduced risk of grid collapses

3) Financial compensation for an SEB which does not receive its due share due to overdrawal by other SEBs or fall in generating agencies' output capability below norms

4) States' shares in different Central projects will have a meaning, as they will be used as operational and commercial datum levels

5) SEBs will have to pay according to what benefits they individually receive from Central stations; they will not have to pay for benefits enjoyed by others

6) SEBs will be encouraged to implement corrective measures in their own operations

7) Hardly any arbitrary assumptions; so, little scope for arguments in tariff formulation

8) The scheme will be fair to all as it would work on a totally reciprocal basis. Utilities could work together with cordiality.

9) Grid discipline will be induced through tariff; only discipline - breakers will financially suffer.

10) Operational and financial autonomy; the whole system would work satisfactorily without continuous goading by a third agency (REB).

11) Reduced on-line role of Load dispatch centres in frequency control; they can lay guidelines and do off-line monitoring.

12) Once relieved of the present fire-fighting duties, the Load dispatch centres could concentrate on correction of voltage profiles, system operation within stability limits, prevention of line and transformer overloading etc.

13) Global accounting will become simpler.

14) Compatible solutions can be worked out for operational and commercial problems of parallel operation with Private-sector and Captive plants, and of inter-Regional links.

15) Captive Power Plants could be integrated into Regional grids, to everybody's benefit.

16) Bilateral agreements and barter arrangements can be easily superimposed.

17) Well-regulated grid frequency

18) Progress in the right direction would restore the confidence of World Bank etc. in Indian Power sector.

SOME COMMON DOUBTS

1) SEBs have no funds, so why bother about rationalisation of tariff. They will not pay in any case.

2) There is no grid discipline, and frequency fluctuations will continue whatever we may do.

3) Due to the present power shortage, overdrawals will continue, even if there are penalties.

4) Frequency-linked tariff is impractical|utopian.

5) SEBs will not accept the proposal.

6) It has not been tried anywhere.

ANSWERS

1) SEBs will end up paying less, not more.

2) The tariff itself will bring about grid discipline.

3) Atleast discipline-followers will not suffer|be penalised for overdrawals by defaulters.

4) There is nothing more practical than this.

5) Firstly, the major suppliers e.g. NTPC have to propose the new tariff structure, and remove SEBs doubts.

6) The underlying principles of incremental cost are world-wide, standard norms.

CORRECTION OF VOLTAGE PROFILES

REQUIRES REACTIVE POWER COMPENSATION

A local phenomenon, which can be corrected locally

NEED – ALREADY WELL-ESTABLISHED

ACTUAL INSTALLATION – requires large INVESTMENTS.

which would come forth only when there is a reasonable RETURN or a SAVING to the investing agency, commensurate with the investment.

So, there should be a reasonable charge for inter-utility transfers of Reactive energy.

At a nominal paisa/kVARh rate, as follows:

A charge for kVARh drawal, and a rebate for kVARh return, while voltage is below 97 %.

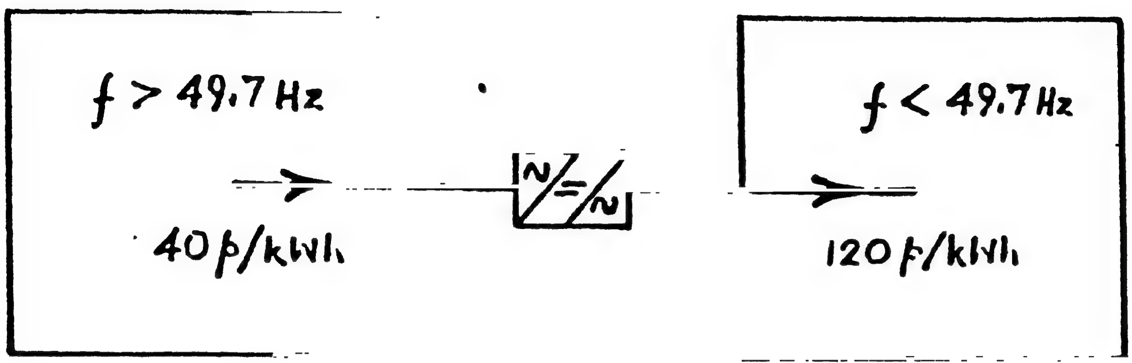
A rebate for kVARh drawal, and a charge for kVARh return, while voltage is 103 % or higher.

No charge for kVARh while voltage is normal

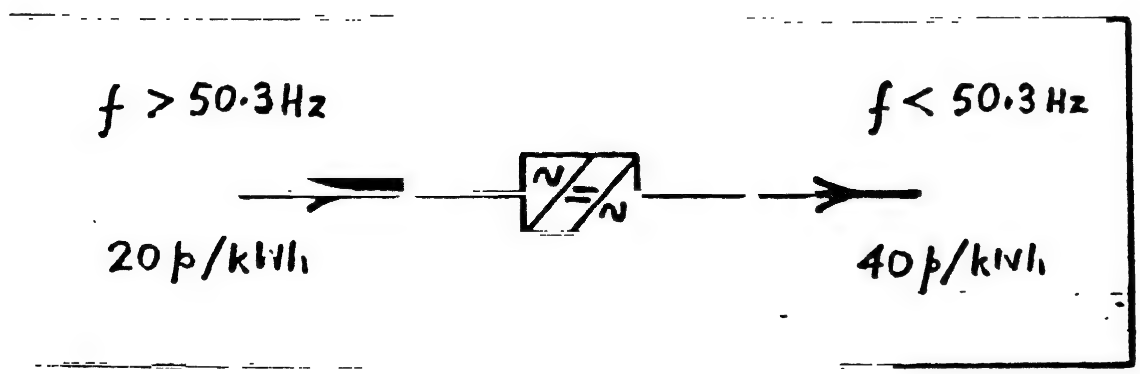
(kVARh is +ve when lagging, and is -ve when leading)

TARIFF FOR INTER-REGIONAL POWER FLOWS

Case - A : Asynchronous ties (H.V.D.C. B/B)



During emergency assitance



While utilising cheap surplus

The difference to go for reimbursing the fixed cost and O&M charges of the H.V.D.C. Station.

Case – B : Synchronous ties (A.C.), while operating without any specific commitment

1) Average of incremental costs of load-centre thermal plants of concerned Regions, while the frequency is normal (49.7 - 50.3 Hz)

2) Average of incremental costs of pit-head thermal plants of concerned Regions, while the frequency is high (above 50.3 Hz)

3) Incremental cost of Diesel-generators, while the frequency is low (below 49.7 Hz)

4) Fixed costs to be totally neglected. Only a paisa per kWh charge as above, on reciprocal basis.

Case – C : Synchronous ties (A.C.), while being used for transfer of a certain quantum of power from agency – A to agency – B

1) Lump sum charges for the defined quantum of power, for emergency assistance or for utilising cheap surplus, to be negotiated between agencies A and B and settled in advance.

2) In case this transaction entails power flow through transmission lines belonging to third agencies, the latter to be reimbursed by agencies A and B for use of facilities and additional line losses.

3) Any deviation in the inter-Regional tie line flows from that required for the defined quantum of power transfer to be adjusted as per Case-B.

NPTC's PLAN OF ACTION

1) Explaining the concept of frequency-linked tariff to all concerned agencies, and proposing its adoption on all-India basis

First round	:	FEB - MAY, 1991
Second round	:	JUNE - SEPT, 1991

2) Finalisation of agreements between|with SEBs, REBs, generating agencies etc. : OCT - DEC, 1991

3) Frequency stabilisation, by putting all turbines on free-governor action : JAN - MAR, 1992

4) Commercial operations as per new tariff structure to start on : 1.4.1992

STILL TO BE WORKED OUT :

- Transmission losses
- Wheeling charges
- Norms for returns on loan|equity
- Rate of depreciation
- Norms for plant availability
- Norms for heat rate, auxiliary power consumption, O&M charges, etc.
- Metering arrangements
- Accounting and billing
- Review of immediate additional requirements for communication, telemetering and load-despatch facilities
- Tackling of Transmission constraints
- Tariff for Private-sector and Captive plants

Planning and Management of Power Distribution System

P.D. Sharma

Heavy investment in power sector and the annual operation of utilities place major demands on the limited financial, technical, managerial resources available and makes it imperative to ensure that these resources are used most efficiently. Utilities must strive to provide electricity at the least possible cost by pursuing optimal investment strategies and operating assets in the most efficient manner. Planning, designing, constructing and operating power distribution systems in order to minimize the economic cost of losses etc. is a critical part of this exercise. On the demand side actions can be taken to modulate the level and pattern of consumer demand to achieve a more efficient utilisation of assets.

The distribution system occupies an important place in any electric power system. Briefly its function is to take electric power from the bulk power source or sources and distribute or deliver it to the consumers. The effectiveness with which a distribution system fulfills this function is measured in terms of voltage regulation, service continuity, flexibility, efficiency and cost. The cost of distribution is an important factor in the delivered cost of electric power.

In brief the problem of distribution is to design, construct, operate and maintain a distribution system that

will supply adequate electric service to the load area under consideration both now and in future at the lowest possible cost. Unfortunately no one type of distribution system can be applied economically in all load areas, because of differences in load densities, existing distribution system topography and other local conditions.

In studying any load area, the entire distribution or delivery system from the bulk power source - which may be one or more generating station or power substations to the consumers should be considered as a unit. This includes sub-transmission - distribution sub-station, primary feeders, distribution transformers, secondaries and services. All of these parts are interrelated and should be considered as a whole so that money saved in one part of the distribution system will not be more than offset by a resulting increase elsewhere in the system.

The distribution system should provide service with a minimum voltage variation and a minimum of interruption. Service interruption should be of short duration and affect a small number of consumers. The overall system cost - including construction, operation and maintenance of the system - should be as low as possible consistent with the quality of services required in the load area. The system should be flexible, to allow its being expanded in small increments, so as to meet changing load conditions with minimum amount of modification and expense.

Currently, on power distribution front, we have problems of high power losses, poor reliability and voltage conditions, safety hazards, communication facilities, data acquisition, management over staffing, inefficient revenue collections, overall ineffective management and high cost operations. There are inadequacies in procedures and working methods particularly related to relations with consumers and power supply development policies.

Distribution system are planned and built for an economic life of 20 - 30 years. Ratings and capacities are based on forecasts of future loading and also complying with certain basic technical requirements in terms of safety and standardisation. The total annual cost of such systems is minimized during their operational life. Optimizing is carried out in two stages in order to simplify the calculations work. Regional systems and distribution substations are optimized separately from secondary substations and low voltage distribution systems. The capacities of regional systems and distribution substation are normally progressively increased in step with increasing load, while the secondary substations and low voltage distribution systems are normally designed from the start for their expected future load level.

When comparing alternative possibilities for system expansion, allowance is made to as great an extent as possible for the implicit supply security of the alternatives. Calculations are based on common values of

safeguards against failures and details of expected number of supply failures per year and their duration.

The planning criteria used vary from one country to another on account of differences in geographical, economic and social conditions. Often the planners judgment and experience play a vital role. At the heart of all planning is a load forecast which is of prime importance. In India a medium term forecast for next 10 - 15 years which can foresee the types of loads and utilisation pattern in urban and rural areas may yield reasonable data for distribution system design. A computer programme can be run considering time and other variables viz population, number of households, tube wells, volume of economic activity (turnover, production etc.), competition with other forms of energy like solar, biogas, oil , natural gas, etc.

Wide range of load forecasting methods exist, almost all computerised methods fall in to one of three categories: Trending, multivariate and simulation methods.

Trending methods encompass a wide class of techniques that predict future load values as a small areas basis by extrapolating past load growth trends and behaviour.

Multivariate techniques encompass methods that perform an extrapolation or "trending" or data that includes more than just load values, e.g. a multivariate method might be based on the relation between electric, gas and fuel oil

consumption, projecting all three in to the future and relying on established mathematical relations and constraints among them variables, to improve the forecast over one that works only with electric-usage. Both these methods do not see addition of customers and growth of per capita usage, as a result they often fail to anticipate major shifts in distribution load growth.

Simulation methods by contrast address these two phenomena separately by land use analysis. The advantage is that analytical land use techniques are the most accurate and useful spatial forecast methods are available.

The design of a distribution - system should be based on minimum and reasonable line losses in H.V. and L.V. lines and distribution transformers and proper voltage regulation as per the statutory provisions. Trend of system losses in India as well as in some Asian and European countries is given below:

India	19.7 to 20.8%
China	8.13%
Japan	5.71%
France	7.31%
U.K.	8.63%

Power is a highly capital intensive industry. To generate 1 MW of power an investment of about Rs.2.0 crore is required and an equal amount is needed for its transmission and distribution to the ultimate consumer. It is therefore

absolutely necessary to keep the losses to the least minimum possible. Annexure I gives the analysis of losses in a distribution system while annexure II give methods of loss reduction. The losses comprise technical losses and commercial losses. The ultimate aim of system designer is to restrict the technical losses to a reasonable level since they can not be totally eliminated.

Distribution losses and voltage regulation have a direct relationship.

$$\%\text{ energy loss} = \%\text{ regulation} \left[\frac{0.8 \times L.F. + 0.2}{\text{Cos}\phi\,(\text{Cos}\phi + X/R\ \text{Sin}\phi)}\right]$$

where X = per phase reactance

R = per phase resistance

Loss factor = 0.8 x L.F. + 0.2

Taking 11 kV line with weasel conductor having 3 feet spacing, assuming LF = 0.15 and p.f. - 0.7

% energy loss at 8% regulation = 4.01%

% energy loss at 20% regulation = 10.2%

Therefore improving voltage regulation will automatically reduce the line losses within practical limits. Fixed capacitors to the extent required to avoid over voltages at light loads periods should be used. These can be on 11 kV side. The additional capacitors required under full load conditions should be applied as switched capacitors on L.T. side of the distribution transformers.

Many times the incoming voltage itself is not 11 kV. The increase in line losses in the 11 kV section, if the incoming voltage is less by 10% is given below:

$$\text{Present line losses} \times \left[1 - \left(\frac{11}{.9\times 11}\right)^2 = .2346 \right]$$

$$= 23.46\% \text{ more losses.}$$

H.V. line design

The standard voltage normally used is 11 kV. Feeder length and conductor sizes are to be decided considering the following:

(i) Initial load, load factor and power factor

(ii) Annual percentage load growth

(iii) Cost of conductor and revenue which the line would realise

Standard charts to decide feeder length based on MW-kM capacity of conductors depending on maximum load for a known V.R. can be used to decide size of conductor.

If primary feeders are arranged so that their loads can be switched from one feeder to another under emergency conditions, sufficient spare capacity must be built in each feeder so that it can carry any load which can be connected to it. Many interrelated factor affect the choice of rating for a primary feeder. Some of the important factors are the nature, density and rate of growth of load, the necessity for providing spare capacity for emergency operation, the type and cost of circuit construction which must be used, the

design and capacity of the associated substations, the type of regulating equipment necessary and the quality of service required. Some kind of loads, such as welding and arc furnaces may have to be segregated to a separate feeder or feeders to prevent their adversely affecting other loads. The various interrelated factors mentioned and others that affect the proper rating of a primary feeder can in general be boiled down to two major factors namely, cost and quality of service.

L.V. line

L.V. line should be minimized where majority of problems are in the area of energy loss, VR and interruptions are involved. This can be achieved at the cost of extra H.T. line and small capacity of distribution transformers to feed each consumer or a small group of consumers separately.

It should be however ensured that the benefits accrued by reducing L.T. line are not offset by the extra cost of installing additional H.V. line.

ABC system should be used. This will reduce cost of supports, way leave problems, minimize accidents due to snapping of conductors together with uninterrupted supply and preventing theft of energy by tapping the overhead line.

Distribution transformers

Estimation of peak demand per prospective consumer and average diversity factor for a group of consumers would

enable in deciding optimum rating of transformer taking into consideration also cost of losses and reduction in equipment life as a result of overloading etc.

The economical size of distribution substation to employ as a particular radial system depend on load density, sub-transmission arrangement, unit cost of sub-transmission circuits, unit cost of primary distribution feeders, cost . of land and other factors. At times it may be desirable to have number of average size distribution transformer substation rather than having one large distribution transformer. The location of substation normally be at the load centre.

Regional switching stations are sited so that resulting costs for the supply system and onward distribution system are as low as possible. Overhead lines and outdoor sub-stations are used wherever possible. Standby capacity to guard against transformer faults is normally provided in the form of spare transformer or equivalent standby capacity may be available over distribution lines from another sub-station.

The secondary sub-stations normally have only one transformer. Provision of spare transformer is justified in areas of high load density with high failure sensitivity. Instead transportable standby units are used where necessary.

While designing an electrical distribution system, overall life cycle cost of the system are considered, with the objective of minimizing the present value of total annual

costs. Total annual costs include construction, operation and maintenance, losses and costs of supply interruptions. Evaluation of interruption costs is generally performed separately.

Although construction costs for distribution systems are well known, operating and maintenance costs are more difficult to estimate and therefore expressed as % of capital cost.

Cost of losses

Cost of losses depends on the magnitude of the losses, system utilisation time and price of electrical energy. Design ratings therefore now often based on economic factors rather than on previously as purely thermal ratings. Loss utilisation time can be calculated exactly if a known load diagram is available.

Security of supply

Supply quality depends on system frequency stability, voltage quality and security of supply.

Supply failure costing

Optimum security of supply is regarded as having been achieved when the distribution utilities costs for improving the distribution system equal the resulting corresponding reduction in customers costs caused by supply failures. Values arrived at therefore cost investigations of a large number of different customer categories are therefore often

used as a basis for quantifying the cost of supply failure.

Frequency of supply failure

The other component in evaluating the cost of supply failure is expected average duration of supply failure per customer and the number of failures.

Planning of a distribution system network is a difficult and complicated exercise to take care of the foregoing issues and CAD programmes are available, which should be used. Good power network planning is the result of a balance between investments that are immediate expenditure, losses that are future expenditure and quality of supply for consumers.

Management of Power Systems

Improved power system management can improve a utilities performance. Because electricity generation must reflect demand more closely than is necessary in other forms of energy supply, appropriate measures for technical management are essential to sound performance. Also technical management of given utility's power system includes not only the management of its own power system, but, where such arrangements exist, the management of power inter change arrangements with neighbour utilities as well.

Load Management

The deliberate influencing of consumers electricity demand to optimize overall operation, efficiency and cost of power supply system - is one method of achieving balance

between electricity demand and supply. Load management presents the overloading of generators and distribution equipment, thereby improving operational efficiency and reduces the need for future investment in generation & transmission capability. When investment resources are limited, load management is often more economical than investment in system expansion. Furthermore control of demand can improve load forecasting and achieve more equitable loading of thermal plants.

Technique of load management

1. Rostered form of load shedding whereby power supplies to consumers in different blocks are shut down for a few hours each in rotation.
2. Staggering work hours and/or holidays and by assigning power and energy quotas to major consumers. Consumers can often adjust their activity schedules so as to minimize inconvenience, discomfort or production losses. This method can considerably improve load factors where industrial establishment account for substantial share of power consumption.
3. Tariff incentives for effective load management. The use of time of day rates, minimum charge, excess consumption penalty, maximum demand charge, penalty for connecting excess load can be effectively used.
4. Controlled load shedding of selected consumers is another viable method for exercising limited control over peak demand. The "intcrruptible" load is a common form of

switching control. Local controllers, such as time switches, priority relays (which prevent two or more high load appliances to be used together) and demand limiters (which schedule loads or shed loads in predetermined schedules) may be installed at the consumers end. One way communication with load management devices can achieve useful load clipping. Some two way communication systems are also available and permit other functions such as remote meter reading and data acquisition.

To obtain maximum benefit load management systems must be integrated with Supervisory Control and Data acquisition (SCADA) system within the utility control structure.

Computerisation

Its a must for efficient management of a utility as its size increases. However, application in Power system in our country is in initial stages. It is also essential to have an efficient central control centre.

Offline Applications

Inventory Control, customer service & billing. Other applications include generation and transmission expansion, load forecasting, Accounting and Financing, Information systems etc. etc.

On Line Applications

In Asian countries is still confined to relative

simple operations such as Power plant control, data logging and training simulators. SCADA systems incorporates several functions, which include automatic generation control, economic dispatch control, on line load flow studies, automatic voltage control and switching of power networks.

SCADA/EMS systems are required in order to effectively monitor and control the transmission system to maintain or improve the reliability and quality of supply to customers but some are justified economically by potential savings in operating costs such as reducing fuel costs through more efficient use of thermal generating units.

SCADA System

1. Provide necessary monitoring and remote control of substations and generating plants to maintain or improve reliability and quality of supply to the customers and permit faster restoral of service following outages.
2. Permit Unmanned operation of substations, thereby making skilled operators available for duties at control centres or generating plants and avoiding problems in recruiting and training qualified substation operators.
3. Coordinate with planned network growth.
4. Replace obsolete unmaintainable equipment. A SCADA master station has a useful life of 10/12 years. RTU have a useful life of 10/15 years.
5. Provide a more complete and accurate network operations reports & data.

AGC/EMS Function

1. Provide automatic control of network frequency to improve quality of supply to customers.
2. Reduce system energy losses and improve quality of supply & customers by better monitoring and control network voltages.
3. Reduce annual fuel costs by improving the efficiency of operation of thermal generating units and better consideration of hydro & thermal resources.
4. Permit better assessment and control of intercharge transactions by interconnecting utilities.
5. Permit better use of available transmission line and transformer capacities which sometimes may allow delay of major transmission reinforcement projects.
6. Permit more effective initial and refresher training programme for SCC operators by using power system simulators.

The Asian Development Bank made a study of 21 utilities in the Asian - Pacific region and have made recommendations which will benefit the utilities depending upon the present state of development of system control and communication facilities and operating techniques for the specific utility. These are given in appendix III.

Commercial or financial management aspects of a utility's operations are as important to its performance as its Technical management. Tariffs have a strong and direct impact on the financial state of utility. Equally important

are conditions for obtaining finances from external sources, the evolution of demand compared to capacity, the no. of new system facilities under construction and management of construction programme. Manpower utilization and training are also important aspects of a utility's performance. These should be given adequate attention.

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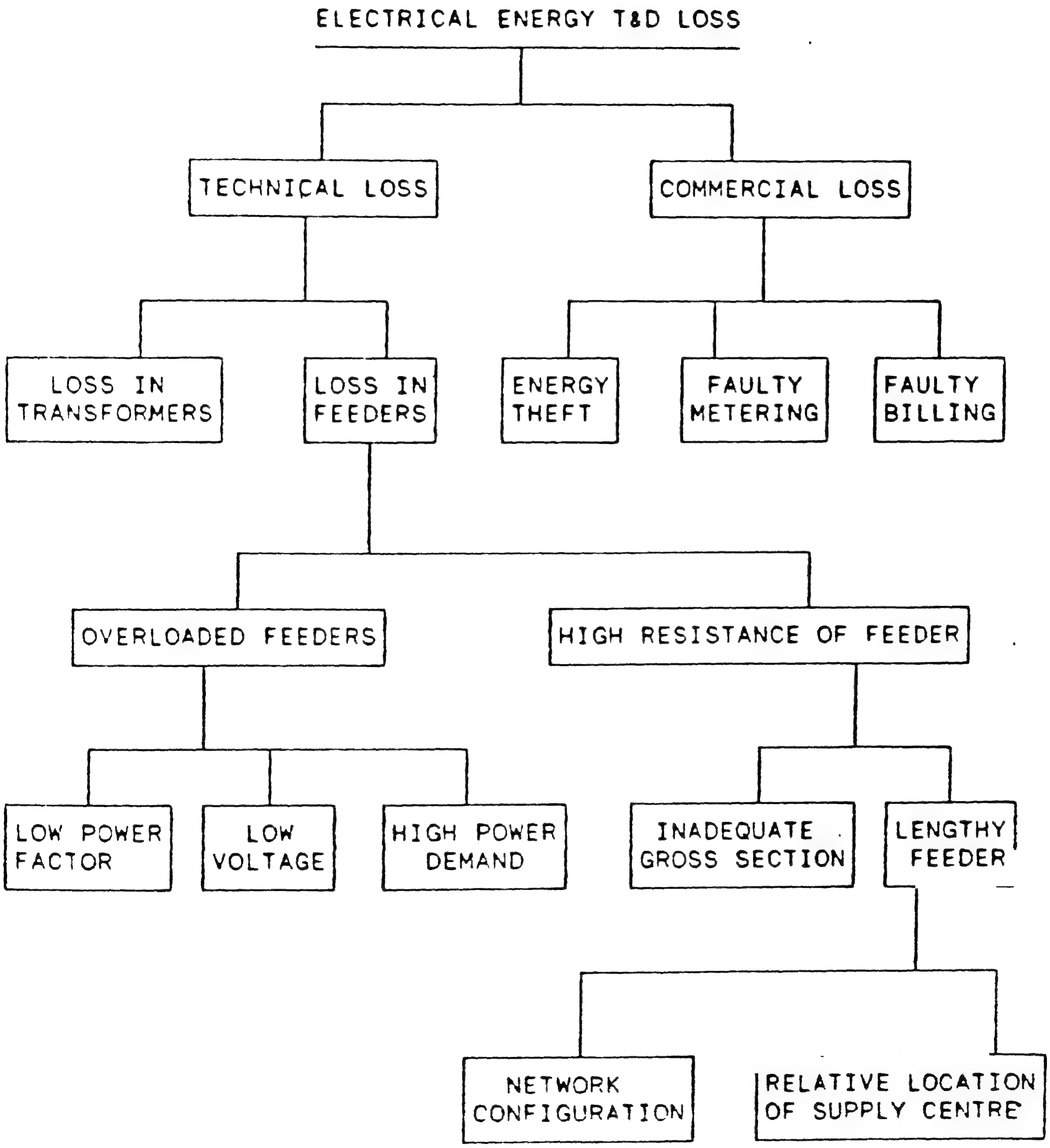
Annexure I

Electrical Energy T&D Loss



Annexure III

1. Establish, extend or upgrade system control center facilities for monitoring and remote control of transmission network to predict and avoid conditions leading to outages, reduce the time needed to restore service to customers following unavoidable outages, reduce operating errors and reduce the need for skilled operators at substations.
2. Establish, extend or upgrade system control center facilities for monitoring generation and automatically controlling system frequency to improve the reliability and quality of electricity supply and reduce production costs.
3. Establish or upgrade system control center, remote control facilities for hydro and standby gas turbine and diesel generating units so these units can be started and loaded quickly to reduce the duration of outages.
4. Provide sufficient, competent support staff at the system control center and upgrade analytical tools to improve short-term load forecasting, generation scheduling and post-analysis to optimize utilization of thermal and hydro generation resources, maintain or improve reliability of electricity supply and reduce production costs.
5. Improve transmission network voltage control facilities and devices to improve the quality of electricity supply and reduce system losses.
6. Establish, extend or upgrade the communications facilities required for effective system monitoring and remote control as well as for system maintenance and administration.

7. establish, extend or upgrade automatic underfrequency load shedding schemes (and specialized teleprotection schemes for load-balancing or islanding) to maintain or improve the reliability and quality of electricity supply and minimize cascading system outages and blackouts.

8. Improve techniques to plan an annual coordinated schedule for routine inspection and overhaul of generation and transmission equipment and provide the resources necessary to do the work on schedule in order to reduce forced outages and minimize planned load-shedding.

9. Establish a uniform method of recording, analyzing and reporting system and equipment outage statistics to facilitate year to year comparison of system and equipment performance by a utility and between utilities.

10. Establish or upgrade formal and practical training programs for system operations staff and electronics maintenance personnel.

11. Encourage interconnections between neighboring utilities and establish or upgrade tieline monitoring and control facilities necessary to achieve improved reliability and quality of electricity supply and reduced production costs.

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ROLE OF GOVERNMENT & SEB'S IN ENERGY CONSERVATION

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Energy Management Centre

NEED FOR ENERGY CONSERVATION

The demand for energy in India has been growing rapidly, and, consequently, investments in the energy sector over the past three Five Year Plans have been taking up almost 1/3rd of the total public sector outlay. In the Eighth Plan if we are to add 38,000 MW power capacity, we shall need to invest Rs.1,20,000 crores. The exercises carried out by the Energy Demand Screening Group set up by Planning Commission indicate that our requirements for energy by the year 2004-05 will pose a staggering task in terms of arranging for adequate energy supplies and investments that would be required. In addition to the increasing capital intensity of the energy supply sector, there is the danger of growing dependence on imported oil which would pose an unusually high burden in terms of foreign exchange outflows if demand materializes to the levels projected. It is therefore not too late for the country to shift the focus of its energy policy towards demand management and energy conservation and formulate and implement policies by which the growth in demand can be reduced without sacrificing economic growth. Efficient utilization and conservation of energy will have to be given as much (if not higher) priority as supply of energy in the country's future plans and programmes. In fact based on considerations of economic efficiency this deserves the first priority.

WHAT IS ENERGY CONSERVATION ?

In a very broad sense Energy Conservation means economising on the use of energy without in any way affecting the economic growth and development. It has many facets and various actions ranging from improving the efficiency of energy extraction, conversion, transmission and distribution

to increasing the productivity of energy use to interfuel substitution to bringing about a structural change in the economy to changing the energy use habits of consumers result in achieving economy in the use of energy and are therefore, synonymous with energy conservation.

As energy conservation can reduce the need for energy, it provides a range of important benefits. First, conservation can save money - in the short run by reducing energy cost, and in the long run by substituting for more expensive power plants. Second, conservation avoids the tremendous social and environmental costs incurred by energy facilities, including emissions of Carbon-di-oxide and other pollutants.

Because of the wide range of benefits, conservation is occupying an increasingly central role in the energy sector in developed countries. Developing countries like India stand to benefit from conservation despite their relatively low per capita use of energy because conservation can help to reduce their relatively high demand growth rates and the associated future capital requirements to manageable levels.

ENERGY CONSERVATION OBJECTIVES

In the Indian context, the Energy Conservation Programme is oriented towards fulfilling the following broad objectives :

- Improving the efficiency of utilization of energy in the existing stock in our production, distribution and consumption systems,

- Bringing about a reduction in the demand for oil products and electricity,

- Curbing the consumption of oil to minimum possible level,

- Ensuring that "new stock" coming to stream is inherently energy efficient.

- Management of peak-load of electricity supply systems with a view to improving system load factor,

- Ensuring that the fuel mix in the economy is consistent with the long-term fuel policy of the country, and

- A reappraisal of economic development strategy especially those elements of the strategy which have a direct link with energy demand such as technology choice, location policies, urban growth, mechanisation in agriculture, concern for indigenous production of certain products etc.

ENERGY CONSERVATION: GOVERNMENT'S ROLE

Energy conservation by its very nature is decentralized in nature and hence, unless the multitudes of consumers of energy adopt energy conservation as way of life and pay attention to physical plant and equipment with a view to improving their energy efficiency, large scale gains in energy efficiency are not possible. Government on its part can play only a catalytic role to initiate desired type of behaviour with the following :

(i) Over-all programme coordination

Create necessary Institutional set-up and infrastructure for programme formulation, co-ordination and implementation.

(ii) Create demand for Energy Conservation

Initiate actions to boost demand for adopting energy conservation practices and to strengther the supply response,

(iii) Adoption of Energy Conservation

Initiate actions to actually bring about adoption of energy conservation practices and/or installation/ retrofitting of energy conservation equipment.

(iv) Policy on Rational Use of Energy

Undertake Policy initiatives to bring about rational use of energy in the economy

I. OVERALL PROGRAMME COORDINATION

The institutional structure for determining and directing energy efficiency policies in India is a two-tier one. The Energy Conservation Cell in the Department of Power, Ministry of Energy, formulates policy, designs the energy management programme and ensures effective coordination between interested Ministries and other entities. The Energy Management Centre (EMC) is the executive agency under this policy function designed to implement and monitor the Energy Conservation programme.

Apart from having the above set up at the Centre, to provide impetus to the State level efforts in the conservation area, following additional infrastructural strengthening arrangements are proposed :

(a) Set-up State Energy Conservation Cells, to be located in the State Electricity Board and State Energy Development Agency, for planning, implementing, monitoring and reviewing the various energy conservation programmes.

(b) Set up National Energy Usage data-base and develop energy consumption norms for key sub-sectors

(c) Setting up of Energy Training Institutes in various regions

(d) Setting up of Energy Advisory Centres in various States

II. CREATE DEMAND FOR ENERGY CONSERVATION INVESTMENT

To create demand for energy conservation, investment following programmes are being implemented :

(a) Provide subsidy for conducting Energy Audit and Feasibility Studies.

(b) Commission Demonstration Projects to promote energy conservation equipments/technologies which are in the pre-commercialisation stage.

(c) Model Depot Scheme for the State Road Transport Undertakings

(d) Provide R & D Grant-in-aid for development of energy efficient devices / equipments.

(e) Programmes for rectification of existing agricultural pumps.

(f) Promotion work related to Energy Conservation by launching mass-media based awareness campaigns, production of video films, bringing out case studies, product/consultant directories, instituting "Award Schemes", etc.

(h) Training Programmes in the area of Energy Conservation for :

- * Energy Managers/Auditors * Supervisors
- * Trainers * Shop Floor Workers
- * SEB Personnel * Agriculture Pump Auditors

III. ADOPTION OF ENERGY CONSERVATION

Energy efficiency improvement ultimately requires the undertaking of investment projects. The economic policies, the conservation programmes and institutional efforts would serve the purpose variously of boosting both demand for energy-savings projects, and the supply response in terms of closing the expertise gap that often exists. At the plant level, however, such boosted demand and supply capability would still remain to be converted to concrete investment plans. To facilitate such investment plans, following policies were initiated during the 6th/7th Plans.

- Fiscal Incentives

  - o 100% depreciation on notified energy conservation equipment

  - o concessional excise/customs duty on notified energy conservation equipment

- Other Incentives

  o Providing finance for installing energy conservation equipment

    * IDBI Equipment Finance Scheme
    * Petroleum Conservation Research Association Boiler Modernization Scheme
    * Soft Loan Scheme for Modernization

Notwithstanding these initiatives, however, there is a need expressed by several industry associations, chambers of commerce and trade bodies to institute a revolving fund for energy conservation investment. Institution of such a fund, which could be operated through the Development Financial Institutions, is under Government's consideration.

IV. POLICY ON RATIONAL USE OF ENERGY

Several initiatives, as listed below, have already been taken by the Government to further the uptake of rational use of energy activities in the various sectors of the economy.

- allowing private participation in power generation - this is expected to provide the needed boost to cogeneration

- Industries under administrative price control such as cement, paper, aluminium have been decontrolled, consequently inertia that was there for cost reducing measures (due to cost plus pricing) has been overcome leading to major investments being made in these industries for energy conservation : cement is a case in point where large investments have been made to convert energy inefficient wet process plants to energy efficient dry/semi-dry process plants.

- Specifying minimum economic size of unit for various industries to reap the benefits of economies of scale.

Disclosure of information on energy conservation in the Annual Reports of 21 industries, under the (companies Disclosures of Particulars in the Report of the Board of Directors) Rules 1988.

A decision was taken by the Government in respect of industries under administrative price control that for the period 1982 to 1985 any improvement which results in conservation of energy or reduced consumption of utilities/raw material etc. is made neither the cost nor the benefit thereof would be recognised while computing retention price for a period of six years from commissioning.

SEB's ROLE IN ENERGY CONSERVATION

SUPPLY SIDE : IMPROVING ENERGY EFFICIENCY

Energy audit/energy conservation studies at thermal power stations be carried out using modern technique covering the complete system from coal handling plant to grid alongwith lighting, and air conditioning has identified the areas for detailed energy audit and draw detailed plan for implementing energy efficiency measures. The following main areas of Thermal Power Stations identified are :

I.

A. Coal Handling Plant : Identifying the weak areas which inhibit the optimum utilization of equipments from wagon tippler to coal conveying system.

B. Boiler

a. Energy loss in flue gas.
b. Loss due to improper combustion resulting in loss of coal and oil in the combustion products and unburnt solid fuel which goes waste alongwith ash.
c. Radiation loss due to poor insulation.
d. Loss due to excessive boiler waste blow down.
e. Excessive consumption of furnace oil.
f. Loss due to ingress of air due to improper sealing of boiler resulting in heat loss, excessive erosion of second pass equipments and over loading of ID, milling system and ESPs etc.. This also causes excessive energy consumption and restricts the output of boilers.

C. Turbine : Besides wastage of large amount of heat in circulating waste there are other losses in the turbine which should be measured and minimized such as, nozzle loss, blade friction loss, disc friction loss, partial temp. loss, diaphgram leakage, and blade tip leakage, residual velocity loss, wetness loss, shaft glad leakage loss, journal and thrust bearing loss, governor and oil pump loss etc.

D. Condenser : There are maximum opportunities of energy conservation by improving the performance of condensers. Even a slight improvement in condenser vacuum increases the efficiency of the turbine substantially. The energy audit of condenser requires measurement of loss due to air ingress, dirty/chokced tubes, quantify and temperature of inlet cooling water system.

E. Energy consumption in auxiliaries

F. Energy loss due to steam and water leakages

G. Lighting -Optimum utilization

II. TRANSMISSION & DISTRIBUTION LOSS MINIMISATION

III. DEMAND SIDE MANAGEMENT

Several utilities in the United States and many developed and developing countries have initiated energy conservation programmes at the premises of consumers. These initiatives range from providing advisory services on the rational use of energy (RUE) to conducting subsidized energy audits to providing fiscal incentives and financial support to the actual installation of conservation equipments.

Considering the success of RUE activities, the Annual conference of Power Ministers of States, held in New Delhi on 11th & 12th of September, 1990 discussed and deliberated at length on the efficacy of involving State Electricity Boards in RUE activities.

Accordingly the following Action Plans were adopted by the Conference :

- To set up an Energy Conservation CEll, headed by a Chief Engineer, in each of the States/SEBs, within a month.

- These cells are to be manned by an adequate staff, wholly dedicated to energy conservation work. The personnel deployed for the cells should be imparted training in conservation measures through participation in special programmes devised for the purpose.

- A 10% reduction in specific fuel oil consumption in thermal power plants during 1990-91, as compared to 1989-90 consumption.

- Allocation of funds by each of the STates from their plan funds for energy conservation measures.

- Fiscal incentives to be devised by the States for promoting energy conservation and for setting up of co-generation plants. Disincentives to be introduced for wasteful uses of power, wherever practicable.

- Each SEB/State Energy Energy Development Agency to undertake energy audits of atleast 40 large scale industrial units and 40 small/medium scale industrial units in 1990-91. For this purpose, assistance on cost sharing basis could be availed of either from Development Financial Institutes like IDBI, or from the Department of Power, by submitting suitable proposals.

- New Power connections in Agricultural sector to be give only where ISI mark pumpsets are installed.

- To intensively undertake a programme for rectification of existing agricultural pumpsets that would cover atleast 1/4th of the existing pumpsets in each State. The Department of Power would consider extending assistance to the State on receipt of appropriate proposals from the States/SEBs.

- To undertake publicity and awareness campaign among users of electrical energy, as a supplement to Central efforts in this direction. Organisation of Conservation Day, exhibitions and field level workshops for different categories of consumers in each State.

- To undertake demonstration projects on energy conservation, such as energy efficient lighting, such as energy efficient lighting, chilled water storage systems for air-conditioning load, shifting of industrial/commercial load from peak to off-peak periods, etc. on cost sharing basis by the user & SEB, 50% subsidy could be considered, provided the technology to be demonstrated has not been commercialized but has been proven on pilot basis or is being tried in India for the first time.

- To accord preference to the BIS approved/ISI marked electrical equipment.

EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

INTRODUCTION

1. Our country had to live with shortfalls of varying degrees in the supply of power since almost the beginning of the planned era. Inspite of an investment of the order of Rs.77000 crore for the sector so far (which is equivalent to about Rs. 38500 crore at 1991-92 price level) the per capita consumption of electricity in the country is presently at the level of 250 units as against 15000 to 20000 units in other developed countries. The present level of country's peak power shortage is also of the order 16 per cent. As regards the future, the 14th Power Survey Committee have projected demand growth rate of the order of 8 to 9 per cent on an annual basis in the country. These factors would suggest an urgent need for creation of an adequate base of power generation and transmission facilities in the country to cater for the projected electricity demands and for improving the quality of life of the masses in general. The power sector activities, however, are highly capital intensive and considering the present resource crunch, it would follow that while on one hand there is an urgent need to mobilise adequate resources for supporting the required growth of the power supply industry, it is also essential that the anticipated gap between supply and demand of power is bridged most cost effectively by looking at the available options both on the supply and the demand sides. The report starts by giving an overview of the power sector and then goes on to assess the emerging power scenario by the end of the 10th five year plan (2006-07). Further, based on the indepth analysis of the

results of extensive power planning studies pertaining to various issues/constraints relating to the power supply industry, the report concludes by suggesting appropriate strategies on the supply as well as the demand side to deal with the major problems that the power sector is anticipated to face.

NATIONAL POWER SCENE - 'An Over View'

2. The seventh five year plan ended in 1989-90 with achievement of more than 96 per cent in terms of the plan targets. Inspite of this, the shortages in energy as well as peak power supply have continued forcing the power supply industry to resort to frequent load sheddings. The peak power shortage during 1989-90 at the national level was more than 16 per cent with a maximum of 23 per cent in the Southern Region followed by 22 per cent in the Eastern Region. The energy shortage on all India level during the period was about 8 per cent with a maximum of 15 per cent in Eastern Region followed by about 13 per cent in Southern Region. These assessments of the power supply situation are based on the usual deterministic approach. The probabilistic approach, applied to the 1989-90 power system conditions show that the average annual loss of load probability (LOLP) at the national level was of the order of 5 per cent with energy not served being more than 1 per cent.

3. Subsequent years 1990-91 and 1991-92 were to form part of the 8th five year plan. The Government, however, decided that these two years shall be treated as two annual plans and the 8th five year plan will commence from 1992-93.

The total anticipated capacity addition on all India basis during these two annual plans will be 6585 MW raising the total I.C. by the end of 1991-92 to 69874 MW comprising 19508 MW hydro ; 48331 MW thermal and 2035 MW nuclear. The all India anticipated power supply position by the end of 1991-92 will be of the order of over 17 percent peaking shortage and over 8 per cent energy shortage.

CURRENT POWER DEVELOPMENT STATUS

4. The second National Power Plan Report brought out by the CEA during 1987, for the first time, had a look on the development of the power supply industry covering the ten years period beyond the 7th five year plan. The report recommended a capacity addition programme of 48000 MW for the period 1990-95 and 62000 MW during 1995-2000 AD for achieving reliability level (LOLP) of 5 per cent. Subsequently Planning Commission set up a Working Group to firm up the power programme for the period 1990-95. Keeping in view the various factors, the Working Group recommended projects aggregating to 38369 MW capacity for commission during the period 1990-95. The Working Group also envisaged capacity addition of 61000 MW during the next five year period of 1995-2000 AD. This level of capacity induction would have ensured reliability level (LOLP) of 5 per cent during the pariod. The requirement of funds for supporting the proposed power programme during 1990-95 as assessed by the Working Group were of the order of Rs. 128000 crore. Subsequently there were indications that funds of the order of only Rs. 70000 to 72000 crore may be available to the power sector. Review of progress of works on various schemes also indicated that apart

from other reasons mainly on account of funds constraint these projects had not progressed as envisaged and the capacity additions during 1990-95 would not have been more than 27000 MW.

5. Review of the current power development status in the country indicates that at present a generating capacity of 34443 MW is sanctioned and is in various stages of implementation, in addition total capacity of 23084 MW has been techno-economically cleared by CEA for future benefits. Out of this total capacity of 57527 MW, benefits of about 37000 MW may be possible during the 8th plan (1992-97).

DEMAND PROJECTIONS

6. The contours of emerging power scenario by the end of 10th five year plan have been established corressponding to the electricity demand projections on region-wise basis as contained in the report of the 14th Electric Power Survey Committee of the government. These projections both for the peak demand and the energy requirement by the end of the 10th plan are given below :

14TH EPS DEMAND PROJECTIONS BY REGIONS

Region	End of 2006-07 Peak Load (MW)	End of 2006-07 Energy Requirement (MU)	Energy Req. Annual Compd. G.R. (%) (1992-2007)	System L.F.by 2006-07 (%)
Northern	48597	264823	7.4	62.20
Western	36549	226646	6.5	70.80
Southern	34375	197823	6.7	65.70
Eastern	21374	118803	7.8	59.50
N.Eastern	3231	15319	9.5	54.10
All India	144295	824076	7.1	65.20

RESOURCES FOR POWER GENERATION

7. The primary energy resources for power generation available in the country are hydro power, fossil fuels namely coal and lignite, oil and natural gas and Nuclear Power. Come other non-conventional and renewable sources of energy such as fuelwood, biomass, tidal, solar, wind and geo-thermal energy are also available but they are in preliminary stages of development. These resources are not evenly distributed over various regions/states in the country. Over the period of next fifteen years (upto 2006-07) it is estimated that hydro power as a renewable source and fossil funds i.e. coal and lignite will remain main source for power generation in the country duly supported by natural gas to some extent. Share of nuclear power is also expected to increase appreciably in future. The details regarding various resources available for power generation are as follows :

RESOURCES FOR POWER GENERATION

1.	HYDRO	-	84000 MW AT 60% L.F.
	(CONVENTIONAL)	-	UNTAPPED Potential 80%
2.	PUMPED STORAGE HYDRO	-	93920 MW
3.	COAL RESERVE	-	186 Billion Tonnes.
4.	LIGNITE	-	5060 Million Tonnes.
5.	CRUDE OIL	-	728 Million Tonnes.
6.	NATURAL GAS	-	686 Billion M^3
7.	URANIUM	-	6700 Tonnes
8.	THORIUM	-	363000 Tonnes
9.	NON-CONVENTIONAL SOURCES	-	BIOMASS (6000 MW)
		-	WIND (20000 MW)
		-	SOLAR ETC.

GENERATION EXPANSION PLANNING STUDIES

8. The generation capcity expansion planning studies have been carried out using the EGEAS software package which has dynamic optimisation algorithm for assessing additional capcity requirement to meet the projected electricity demand subject to specified reliability level expressed in terms of loss of load probability (LOLP). The studies have been carried out for the time horizon of next 15 years (1992-2007 AD) which covers the periods of 8th, 9th & 10th Five Year Plans. The reliability level for purposes of these studies has been assumed to be equivalent to LOLP of 2%. The generation capacity expansion studies in the first National Power Plan Report of CEA brought out in 1983 had aimed for the system LOLP of 1%. However, at the time of formulation of the second National Power Plan Report, it was felt that capacity addition requirements corresponding to LOLP of 1% would be rather enormous and hence a conscious decision was taken to aim at somewhat lower reliability level of 5% LOLP. The question of fixing the target for quality of supply that should be aimed at in these studies was again gone into. Planning studies were carried out to assess the actual reliability level at the end of 7th Plan (1989-90) corresponding to the capacity available for benefit and the demand met at the end of 7th Plan. These studies indicated that the actual power supply quality that could be maintained during the terminal year of the 7th Plan varied between LOLP of 11% and 1.2%. Though, not strictly, the all India annual average of LOLP during the same period was of the order of 5%. Based on normative approach, the all Inaid peaking shortage in the same time frame was 16.7% and the energy shortage was

about 8%. The analysis gives a clear indication that the reliability level needs to be improved from the LOLP of 5% Considering the long gestation periods of power projects, no improvement in the quality of power supply during the 8th Plan period seems possible. Hence, the target to improve the power supply quality level from 5% to 2% has indeed to be achieved in next two plan periods assuming of course that the resources will not be main constaints. Accordingly, these studies have been carried out with the objective of achieving 2% LOLP and energy not served below 0.15% during the terminal year of 10th Five Year Plan. The main assumptions made in these studies are as follows :-

- Optimisation done for end of 10th Plan.
- Anticipated I.C. at the end of 1991-92 considered as fixed system.
- Benefits from sanctioned/ongoing schemes considered as committed.
- Nuclear profile of 10,000 MW taken as committed up to 2006-07.
- Project costs considered at 1991-92 price level.
- Generic supply options based on use of coal/Gas Thermal Plant, Conventional/Pumped Storage Hydro Power Plant.

9. The results of the studies indicated that an additional capacity of about 142,000 MW would have to be added over the period of next 15 years i.e. 1992-2007 to meet the electricity demand by the end of the 10th plan (2006-07) as projected by the 14th Power Survey Committee subject to LOLP of 2%. These details are given below :-

RESULTS OF STUDIES

Generation Source	All India additional capacity requirment (1992 - 2007) (MW)	
Hydro	51637	(37%)
Thermal	81647	(58%)
Nuclear	8145	(5%)
TOTAL	141429	(100%)

Say : 142000 MW

Studies also indicated that out of the existing power plant, capacity totalling about 7500 MW would be eligible for retirement during the study period. Capacity break up is given below :-

Hydro :	530	MW
Nuclear :	420	MW
Thermal :	6732	MW
TOTAL	7682	MW
Say	7500	MW

FIFTEEN YEARS PERSPECTIVE POWER PLAN 'Issues & Strategies'

10. Studies have indicated that the fifteen years perspective of country's power development plan would consist of additional power plant capacity of the order of 142000 MW alongwith matching transmission & distribution systems. These additional generation facilities comprising 52000 MW of hydro, 82000 MW of thermal and 8000 MW of nuclear power plant

capacities are required to ensure that the electricity demand projections of the 14th power survey committee for the end of the 10th plan (2006-07) are met at the reliability level of 2 per cent LCLP with energy not served less than 0.15 per cent. The cost implications of establishing these facilities are enormous. Based on current prices, funds of the order of Rs. 500000 crore would be required to support the envisaged 15 year power development plan. The present indications are that only about 50 percent of the required funding support may actually be forthcoming which would amount to a serious constraint in as far as country's future power development programme is concerned. Another issue which gets highlighted in these studies relates to the area of hydro power development in the country. Studies suggest that over the period of next fifteen years there is a need to add 52000 MW from hydro option as against about 26000 MW hydro capacity added so far since 1973-74. Past experience has shown that the availability of adequate fund has been the main constraint for the hydro power development in the country. In case we fail to achieve the required level of capacity induction from the hydro option, additional capacity of about 15000 MW over and above the total optimum additional capacity of 142000 MW would have to be added from the thermal option to achieve the targetted reliability level by the end of 10th plan. This situation, according to the studies would result in problem of coal availability both in terms of its production at coal mines and its transportation to future power plant sites.

11. Inspite of the severe resource crunch and also the poor financial health of utilities, it is essential that the existing base of power plant capacity is expanded as

recommended above to improve the quality of life of the masses in general. This is suggested very clearly by the analysis of the per capita consumption of electricity in the country by the end of the 10th plan based on the implementation of the generation expansion plan as per the report which indicates that the same would increase to only about 600 units by the end of the year 2006-07 as against the present level of per capita consumption of the order of 10000 to 15000 units in other developed countries. In addition various demand projection exercises carried out by the 14th Power Survey Committee also indicate that the national economy has the potential for electricity demand growth rate of about 7 per cent to 8 per cent annually over the period of next fifteen years. The report after examining various issues constraining the growth of country's power sector recommends strategies for improvement of supply side efficiency and also for efficient management of demand side options for ensuring an overall optimum and sustainable growth of the sector. The report has also sets specific targets to be achieved over the study period for realising anticipated benefits as a result of the implementation of the suggested strategies.

SUPPLY SIDE EFFICIENCY IMPROVEMENT

12. Supply side efficiency improvement measures suggested in the report alongwith specific targets to be achieved over the period of next fifteen years are :

i) **Accelerating hydro power development :**

The share of hydro power in the over all mix of generation at all India level needs to be improved from the anticipated level of 28 per cent at the end of 1991-92 to at least 34 per

cent by the end of 2006-07 by adding hydro capacity of the order of 52000 MW over the period of next 15 years.

ii) **Accelerating nuclear power development :**

Nuclear power development has to play an important role in meeting the long term energy needs of the country. Considering the constraints being faced in regard to the development of nuclear power supply option, the report recommends that at least total nuclear power plant capacity of the order of 10000 MW be created by the end of 10th five year plan.

iii) **Reduction of T & D losses :**

At present nearly one fifth of the generated power is lost by way of T & D losses in our power systems. The report recommends that these T & D losses be reduced from the present level of 23% to atleast 18% by the end of the 10th Five Year Plan. Various ways and means to achieve the target of 18% T & D losses at the national level by the end of the 10th Plan are discussed in the report.

iv) **R & M Programmes for old units :**

For maximising the output from existing thermal units, various R & M schemes have been under implementation for benefits during the 7th Plan period. In addition, Phase-II of the programme for benefits in 8th Plan has also been formulated. As regards, R & M activities for hydro projects, nearly 49 hydro stations with an aggregate capacity of 8834 MW have been identified for the purpose. In view of the benefits that have accrued out of renovation and modernisation programme during the 7th Plan, the report recommends that the R & M programme both for thermal and hydro units should continue during the coming 15 years covering the 8th, 9th & 10th Five Year Plans. Additionally, about 7000 MW of capacity is likely to retire over the period of next 15 years. It is very strongly recommended that life extension programmes in respect of these units be also worked out for implementation.

v) **Formulation of national power grid :**

The regional power grids are being developed with the ultimate objective of achieving the national power grid operation over the future years. The report recommends that the formulation of the national power grid be expedited so as to achieve its completion by the end of 10th Five Year Plan. The studies carried out to quantify benefits on account of the national power grid being in

operation indicate that there would be an over all saving of the order of about 10000 MW capacity by the end of the study period mainly on account of the savings in the generating capacity reserve margin requirements compared to the situation where all regional systems are operated independently, for achieving the same reliability level of 2% LOLP.

vi) **Non Conventional Energy Sources :**

The Department of Non Conventional Energy sources had earlier programmed for materialisation of about 15000 MW of capacity by the turn of the century from various Non-Conventional Energy Sources namely Wind Power (5000 MW), Solar (2000 MW), Bio Mass (6000 MW), Mini/micro Hydro (2000 MW). Though, these benefits have not been considered in these studies, considering the renewable nature of these Non-Conventional Energy Sources and also the fact that their development would have very little impact on surrounding environment, it is recommended that the Government may support these programmes for benefits over the period of next 15 years.

vii) **Environmental aspects in Power Development :**

As regards the recent environmental converns being expressed in various quarters, in as far as the development of new power projects are converned, the experience has been that so far, only a few of the projects have been finally abondoned on account of considerations of adverse impact on the environment. On the other hand most of the power projects have ultimately got their environmental clearances after a lapse of considerable time gap which has only resulted in time and cost over runds of these projects. The report, therefore, suggests that the Deptt. of Environment may consider giving in principle clearances to power projects once they are prima facie satisfied that there are not going to be major adverse impacts on the environment on account of these schemes. Subsequently, detailed environmental impact studies could be carried out and based on the results of these studies, suitable safeguards could be built in the detailed project report to the satisfaction of the Department of Environment.

EFFICIENT MANAGEMENT OF DEMAND SIDE OPTIONS

13. Two specific demand side options which have been considered for planning exercises contained in the report are :

(a) Demand Management and (b) Energy Conservation/ improvement in end-use efficiency.

(a) **Demand Management :**

The demand management basically consists of shifting system load from peak hours to the off-peak hours and thereby improving the power system load factor. The targets for system load factor improvement have been accordingly fixed on region-wise basis to be achieved by the end of the Tenth Plan. For the Northern Region it is recommended that the system load factor be improved by 9 per cent, for Western Region by about 3 per cent, for Southern Region by about 5 per cent, for Eastern Region by about 11.5 per cent and for North Eastern Region by about 6 per cent compared to those projected by 14th Power Survey Committee for the end of 2006-07. These targets of system load factor improvement if achieved by the end of the Tenth plan would result in net saving of about 15000 MW capacity during the study period. The Study Group therefore, recommends that these regional system power factor improvement targets be achieved as specified.

(b) **Energy Conservation :**

Analysis of the consumption pattern of electricity in various categories indicates that the consumption of electricity in domestic as well as in the agricultural sector has been constantly increasing. The share of electricity consumption in the industrial sector, however, has been following a downward trend. The per centage share of consumption in other sectors namely commercial, traction and other categories of miscellaneous loads like public lighting and public water works etc. have remained fairly constant in the past. The analysis, further reveals that the major thrust areas for coservation of electricity are : (i) domestic (ii) industrial (iii) agricultural sectors. The overall energy conservation target of ten per cent over the energy requirement projected by the Fourteenth Power Survey Committee for the end of the Tenth Plan has been recommended in the report. This will work out to about ten per cent savings in the domestic and agricultural sectors and about fifteen per cent saving in the industrial sector by the end of the Tenth Plan by adopting various energy conservation measures and also by promoting end-use efficiencies in these consumig sectors. The studies carried out for quantifying the benefits of employing both the demand management techniques as well as the energy conservation measures as spec[illegible]ed above have indicated that there would be a [illegible]ing of

about 30000 MW capacity in overall terms by the end of 10th Plan if specified targets are achieved.

CONCLUSSION :

14. The Report concludes that if the pace of hydro development is doubled over the period of next fifteen years, targets of system load factor improvement and energy conservation are achieved as specified and also the national power grid is made fully operational with in the said time frame, the net capacity addition required over the period 1992-2007 would get reduced to 100000 MW, as against the total requirement of 142000 MWs for achieving system reliability level of two per cent LOLP and ENS of the order of less than 0.15%. In case, however, all the recommended measures do not get implemented successfully over the study time frame and the capacity addition remains at the level of 100000 MW, the system LOLP would be over fifteen per cent and ENS over five per cent by the terminal year of the Tenth Plan. Thus the Report concludes that the targetted capacity addition should be between 120000 MW to 130000 MW during the next fifteen years period. In addition, the Report also contains recommendations regarding specific allocation of funds for hydro power development, distribution system improvement schemes, schemes for reactive compensation, life extension studies and end-use efficiency improvement plans.

: "AGRICULTURAL TARIFF IN INDIA - A NEW APPROACH"
: REVIEW AND SUGGESTED MODIFICATIONS

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1. The paper seeks to review the agricultural tariff policy prevailing in the States in India: examine the objectives of such policies, and review the implications of concessional tariff on the financial health of the power utilities. The paper also examines the performance of food production in selected States in certain cropping seasons, procurement during the relevant seasons by the procurement agencies, the input costs of various factors of agricultural production, and the support price for selected cereals (wheat and paddy which are the main crops). Agricultural production in India had made rapid progress in the past two decades, primarily due to the support extended to it by the Government in providing subsidised inputs like Fertiliser, Power, Seeds, Irrigation facilities, cheap and easy Credit; Technological support by research and its application through extension workers; and the market support by providing procurement facility at support price. Though self-sufficiency has been gained in food production it is now being felt that there is a need to review the policy of - providing subsidised inputs; how efficient has this mechanism been in achieving its objectives, in delivering the benefits and in reaching the intended beneficiaries. What has been the impact of such policy on other sectors in economy? With the steady decline in the state of economy and the deficit even in the revenue account in the budget increasing, it is time to review the policy regarding providing electric power at concessional tariff to the agricultural sector.

2. It has been noticed that not even ten percent of food grain production is procured by the Government agencies, while the rest goes to the market and is sold at the open market prices. Of course, the open market price is influenced by the support price which becomes the floor price for the most coarse variety. It can be nobody's case to subsidise, indirectly, the fine varieties or the open market trading of agricultural produce except to support it by way of 'open offer' to purchase at the declared support price since agriculture is susceptible to cyclic patterns of production. This kind of support has to be extended even in the most developed economies and can continue to be extended in India on a selective basis, as and when required. An attempt has been made to correlate the agricultural production data, and the electricity consumption by agricultural sector as indicated by the power utilities; the estimated loss due to concessional supply of power for agricultural production and the subventions payable to the utilities on account of supply to this sector.

3. *Key objectives of the policy*

The key objectives of the policy of concessional agricultural tariff could be :-

(a) To increase agricultural production, if the market did not provide adequate incentive and the prices were kept low. This is not the case as the support price, which is remunerative is the floor price and the open market price rules above that level.

The support price is fixed after taking into account the input costs of all factors of production including power. The input costs of power for irrigation and harvesting are 3 to 4% of total cost and even if these are increased, the cost of production would not be affected significantly and can be taken care of through enhanced support price.

(b) To keep the price of food grain low to make available atleast minimum nutrition to the poor population. This objective is being achieved and can be achieved more effectively through strengthening and improving efficiency of Public Distribution System (PDS). However, for PDS, the Government procures only about ten percent of the total food grain production which can be directly and more explicitly subsidised. The PDS can also be widened and strengthened for the weaker sections. There is no justification for subsidising the entire market system of food grains.

(c) To alleviate poverty as very large proportion of agricultural activity is at the level of subsistence farming. However, it is very easy to identify the small and marginal farmer for extending the benefit of concessional tariff, unlike in case of other inputs like fertiliser, seeds etc. Thus, even if the small farmer does not have marketable surplus, the cost of production in his case, which is going to be consumed by the family would be kept low. If he produces fine varieties he can dispose it off in the market and has access to PDS for buying cheaper foodgrain for consumption.' The impact of concessional power tariff for agriculture, on prices and income distribution is an area of examination for economists, but it has been proved time and again that there is no alternative to open market mechanism for economic efficiencies, as long as safety net is provided for the vulnerable sections.

4. As the agricultural tariffs have continued to be low, (in fact, the supply has been made totally free to the agricultural sector in some of the States), the farmers tend to use inefficient motors, as their capital cost is low; do not adopt energy conservation measures and operate on low-load factor. It also becomes easy to hide theft and pilferage by showing higher unmetered supplies. As only fixed charges are recoverable from unmetered consumers, the average revenue per unit from agricultural consumers has gone down even when tariff has not been scaled downwards which is a clear indication of part of system losses being shown as consumption by agricultural sector. The subvention policy, which links subvention to a return on fixed assets ignores the benefit of efficiency improvement and acts as a disincentive. Thus, the increased losses - technical (due to inefficient use of energy) as well as non-technical (loading inefficiency and theft on unmetered agricultural supplies), lack of motivation for efficiency improvement, 'Drag factor' of agricultural supplies (defined as (Ci - Ri) x Pi/Ca where Ci, Ri and Pi denote the cost of supply, Revenue and Proportion of supply to ith category of consumer and Ca the average cost of supply), which denotes the relative drag per unit of sale to that category of consumer: 1/ non-payment of subventions-all contribute to deteriorating financial health of the electricity boards. The sales to agriculture and the system losses (less technical losses) are clubbed together for the purpose of analysis. The delivery cost of 'Transfer of Resources' becomes high and the effectiveness of mechanism in reaching the benefit to the intended beneficiaries becomes quite suspect. It is a well established fact that explicit subsidies for the intended beneficiaries are economically more efficient, can be monitored easily and are open to review for sectoral allocation process.

5. The states have vied with each other in reducing the agricultural tariff and some states have even made it free. The benefit of free supply is linked to certain amount of land-holding, kilowatt rating of the motor used for running the pump for irrigation, or simply free for all agriculturists. In reality wherever free supply for some segment of a consumer category is provided, it would be free for all the consumers of that category. The implications of such free supply are not just the financial loss suffered on the nominal revenue that the utility was getting earlier, but are very far reaching and it triggers losses in many more ways. Some of the important issues that deserve attention are :-

i] Because of free/concessional power supply the average agriculturist uses equipments (like electric motors, threshers etc.) which are not at all energy efficient as the capital cost of such equipment is much less than the energy efficient motors. There is no

1/ An illustration of 'Drag Factor' is given in Annex-I. A sample calculation of 'Drag Factor' of various states from FY 1975 to FY 1989-90 is given in Annex-II.

incentive for the local manufacturers to improve the technology as there is no market for that. Small industrial units in the rural area - flour mill. oil expellers. steel fabricators also use inefficient electrical equipment as they can get cheap energy by collusion with the utility staff who can easily show this consumption by unmetered and flat rate consumers.

ii] There is no incentive for utility managers to actually reduce system losses as they can quite easily inflate the sales to agricultural sector which is given free supply/unmetered supply/charged flat rate regardless of energy consumed.

iii] It is not possible to account for the energy made available in the system which leads to huge revenue leakages. This makes the system opaque and it is not possible to hold the managers accountable for utility's commercial operations, leading to lack-a-daisical organisational culture. The subventions on account of concessional tariff to agricultural and other consumers is restricted to a fixed return on net fixed assets. Thus State Government may be called upon to finance the inefficiencies of the utility. However, the subventions are seldom paid and whenever paid, these are adjusted against counter-claims of interest on Government loans, which may not be due according to the priority of charges laid in the Electricity Supply Act. It results in serious liquidity problem for the utility since costs have been incurred upfront,while subventions follow after a lapse of time.

v] True economic as well as financial costs of concessional/free supply are much more than the loss suffered on actual energy consumed by the agricultural sector. In fact the agricultural sector, which is a mere conduit for transfer of resources, is not the real beneficiary. The delivery cost of these benefits are high and the effectivenes quite suspect. The main beneficiaries of such a policy are relatively bigger farmers who have the tubewells, and electrical equipment for harvesting/threshing etc.

For the years 1985-86, 1986-87 and 1987-88, the data on production per hectare, cost of production per hectare, cost of power consumed and irrigation etc., for wheat and paddy crops in some of the states was analysed. The procurement performance of the Government agencies was also checked.

Following table gives the details of two States (Madhya Pradesh and Punjab) included in the sample:

Table-1 : Production, Procurement and cost of cultivation of Wheat and Paddy in Punjab and Madhya Pradesh

State :	Punjab		Madhya Pradesh	
Crop :	Wheat	Paddy	Wheat	Paddy
Year :	1987-88	1986-87	1985-86	1985-86
1. Total cost of production/hectare (Rs.)	5940	7390	2292	2627
2. Cost of Power & Irrigation/hectare (Rs.)	200	760	162	10
3. Yeild/hectare (Quintals)	34.2	56.7	11.9	17.23
4. Cost of production/Quintal (Rs.)	173.6	130.3	192.6	152.4
5. Cost of power/quintal of production (Rs.)	5.8	13.4	13.6	0.58
6. Total production (million tonnes)	11.08	6.02	42.02	54.18
7. Total Procurement (million tonnes)	4.42	4.28	0.14	5.69

Table-2 : Estimated Loss on account of concessional power supply

State :	Punjab		Madhya Pradesh	
Crop :	Wheat	Paddy	Wheat	Paddy
Year :	1987-88	1986-87	1985-86	1985-86
1. Agricultural Tariff/unit (Paisa)	14.8	9.02	26.39	26.39
2. Average cost of supply/unit (Paisa)	67.57	58.46	66.82	66.82
3. Estimated electricity consumption for production/ quintal (kwh.) * .	39.5	148.5	51.5	33.5
4. Estimated loss on supply to agriculture/ quintal of production (Rs.)	20.84	73.41	20.82	13.54
5. Estimated loss on Total production (Rs. million)	2309	4419	8748	7336
6. Estimated loss if concession linked to procurement (Rs.million)	921	3142	29	770
7. Net direct savings to the State (Rs. million)	1388	1277	8719	6556
8. Net indirect savings (Estimated) 1/	2063.58			
9. Total savings (Estimate) 2/	4728.58			
10.Support Price(SP)/Quintal (Rs.)	173	146	162	142
11.Enhanced support price SP' = SP + E(C̄ -R)	193.84	219.41	182.82	155.54

NOTE :- 1/ From Annex-III

2/ For 1987-88 the savings from Paddy crop have been assumed to be the same as for 1986-87.

* Estimated electricity consumption per quintal of production as per field survey is much less. For 1986-87 Rabi crop in U.P. it was 10.4 kwh. per quintal and in Punjab it was 8 kwh. per quintal of production.

The supply to agriculture in most of the states is unmetered and supplied either free or on flat rate. The quantum of consumption by agricultural sector, therefore, is only an estimate. As it is not possible to verify these sales, there is every likelihood of agricultural sales being inflated to account for losses arising due to inefficiencies of operation, weaknesses in the system, theft, pilferage and misuse of electricity. One would really wonder as to how the transmission and distribution losses are estimated and every year improvement shown. An attempt was made to reconcile the data on agricultural sales; **(a)** as reported in the annual accounts; **(b)** as indicated by CEA based on number of pump-sets, agricultural connected load (which would more or less match the figures as in (a); **(c)** electricity consumption required for optimum irrigation of entire cultivated land irrigated by tubewells including the land under multiple cropping.

The results are given in Annex-III which clearly indicates the divergence in the estimated agricultural consumption as per production data and the estimated supply shown by the utility.

It is in the light of these findings that the authors suggest a linkage between the support price and the power tariff. If SP_0 is the support price of a crop in the base year, and T_0 is the agricultural tariff per unit, which is increased to T during the current year, and E is the electricity consumption per quintal of production of that crop, then new support price SP would be :

$$SP = SP_0 + (T - T_0) E$$

E would vary from on crop to another depending upon energy intensity of the crop (in fact the irrigation intensity); from one region to another depending upon the ground water conditions and can be reviewed from time to time. The estimate of energy consumption for a crop can be done for different agroclimatic zones in the state and suitable weightage given to the production of that crop in these zones for arriving at an appropriate value for the state. A rough sample calculation is shown in Annex-IV which indicates consumption of 12.5 kwh per quintal of wheat production in Punjab in 1987-88 against 39.5 kwh (Table-2) used in calculating the cost of production. The difference in the support price declared by the Central Government and the one calculated as above could be the incremental state support price. The additional cost would be borne by the central procurement agencies to the extent of foodgrains procured by them, by the State Government agencies to a small extent as they donot procure much.

Some of the major advantages of such a tariff linked support price are delineated below :-

i] The burden of concessional agricultural tariff is borne by the exchequer only to the extent of food grains procured by the Government and not for entire production. This can result in substantial savings to the exchequer as the subsidy gets reduced.

ii] Small and marginal farmers can be easily insulated as concessional tariff (but not unmetered supply) can be extended to them.

iii] A forward linkage can be established by announcing the support price first and revising tariff later. This can be done close to the harvesting time to avoid hoarding and market manipulation by traders. There would be a time lag of one cropping season/year between enhanced support price and increased power tariff, but this is better than the time lag of one decade as at present. In fact the average revenue from agriculture has been steadily going down as shown in Annex-II.

iv] The subsidies on account of concessional tariff are explicit, known to the consumer who would desist from misuse as incremental use means additional, even if small, charges to be paid. The power utility can raise the exact bill of subvention on each billing cycle. This makes the cost of Government Policy known explicitly, and policy decisions can be taken accordingly.

v] Market bears the full cost of what it buys.

vi] Farmers are not affected as the market/procurement agency compensates them for increased cost of inputs.

vii] The power tariff need not be increased suddenly by large amount as the mechanism allows gradual increase over a period of time. This makes the system very flexible.

viii] The farmer is motivated to use energy efficient motors and other energy conservation measures. Technological upgradation gets impetus.

ix] As the energy can now be accurately accounted for, the theft, pilferage and non-technical losses can be controlled. Total energy fed into the system can be accounted for. The power utility has the incentive for operating more efficiently. Proper control systems can be put in place. This lends transparency to the system. The power utility is able to bear the

cost of meter reading, billing (the frequency of which can be less than for other consumer categories) and system maintenance. Cost of billing and collection can be kept low either by suitable billing cycle and procedures, and even by using pre-paid electronic card meters or by other suitable methods.

x) Regional differences can be taken care of, and each State can eliminate these subsidies at its own pace. However, in case of large difference in State-support price between two states there is every likelihood of movement of foodgrain to the markets of the state offering higher support price. It would be neither advisable nor feasible to control physical movement of foodgrains. Regional tariff committees can ensure that the difference in agricultural tariffs of contingous states in the region is not very large. If the difference is not large enough to defray the transportation cost the movement of foodgrains due solely to difference in support price may not take place.

xi) It has also been observed that due to cheap electric power farmers tend to over exploit ground water which is lost in evopration. The water table has been gradually going down and some states have started declaring certain areas as 'dark zones' where no more exploitation of ground water is possible. The ecological impact of such actions is likely to emerge as an area of concern in future.

ANNEX-I

Drag factor can be used for comparing various power utilities on a single factor which takes into consideration their relative consumer-mix, cost of supply and tariff structure. However, it does not help in revealing the underlying causative factors but only demonstrates the impact of these three variables on the performance of the power utility.

Drag Factor is a measure of net negative-contribution of a consumer category to the recovery of cost of supply. It is defined as:

$$Di = \frac{(Ci-Ri)}{Ca} \times Pi$$

Where	Di -	Drag Factor for consumer category i
	Ci -	Actual cost of supply to the consumer-category i
	Ri -	Average Revenue from the consumer-category under consideration.
	Ca -	Average cost of supply of the power utility.
	Pi -	Proportion of total sales, sold to ith consumer category.

As an illustration let us assume there are only three categories -Domestic, Agriculture and Industry, who are sold 10%, 30% and 60% of energy at 60 paisa/unit, 20 paisa/unit and 140 paisa/unit respectively. The actual cost of supply to these consumers is 80 paisa, 120 paisa and 60 paisa/unit respectively and average cost is 80 paisa/unit.

Thus Drag Factor of various consumers Dd Da Dh (the suffix denoting Domestic, Agriculture, and H.T. Consumers) would be as follows:

$$Dd = \frac{80-60}{80} \times 0.1 = + 0.025$$

$$Da = \frac{120 - 20}{80} \times 0.3 = + 0.375$$

$$Dh \quad \frac{60 - 140}{80} \times 0.6 = - 0.600$$

$$\text{Cumulative Drag Factor } Dc = Dd + Da + Dh$$
$$= - 0.2$$

Profit per unit is given by the product of Cumulative Drag Factor and the average cost of supply i.e. -0.2 X 80 = 16 p/unit. Negative drag indicates contribution to profit. Drag Factor of particular consumer category multiplied by average cost gives the loss/profit per unit of sale to that consumer category.

Further variations in the drag factor can be made by using average revenue instead of average cost, which would show net contribution or drag on the revenue earned by the entity. However, average cost (before interest and taxes) is a better measure as the allocation of interest expenses, cross-subsidisation and impact of different capital structures can lead to misleading conclusions.

Average Cost of Supply (ps./unit)	16.41	20.14	21.22	22.6	26.76	31.17	36.52	43.37	49.39	55.3	60.9	69.25	77.63	83.26	91.73	95.54
Average Rate of Realisation (Agricultural)(ps./unit)	22.78	24.11	25.89	24.15	16.85	16.84	15.64	15.58	12.72	13	9.73	8.99	7.8	8.65	9	9
% of Agricultural Sales to Total Sales	8.86	10.91	9.93	10.13	12.02	11.56	12.21	12.28	24.35	14.14	18.71	16.81	17.54	18.19	18.88	18.85
Drag Factor	-3.44	-2.15	-2.19	-0.69	4.45	5.31	6.98	7.87	18.08	10.82	15.72	14.63	15.78	16.30	17.03	17.07
Meghalaya																
Average Cost of Supply (ps./unit)	0	25.15	22.15	25.12	36.27	39.38	27.99	28.36	34.47	42.41	47.5	53.2	89.22	78.73	85.96	103.36
Average Rate of Realisation (Agricultural)(ps./unit)	0	0	0	0	0	0	0	0	0	0	0	40	21.05	24.79	22.06	21.43
% of Agricultural Sales to Total Sales	0	0	0	0	0	0	0	0	0	0	0	0.01	0.42	0.38	0.38	0.39
Drag Factor	ERR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.32	0.26	0.28	0.31
Orissa																
Average Cost of Supply (ps./unit)	16.19	16.68	19.85	21.58	26.87	33.11	37.56	36.8	44.24	46.29	49.05	69.83	77.27	81.15	83.25	77.94
Average Rate of Realisation (Agricultural)(ps./unit)	24.09	25.34	22.7	15.06	8.85	8.88	18.13	17.12	18	17.97	18.53	22.44	18.97	19.45	22.05	22.07
% of Agricultural Sales to Total Sales	0.45	0.36	0.58	0.81	1.23	1.98	1.88	2.19	2.71	2.28	2.02	2.27	4.37	2.51	3.14	2.97
Drag Factor	-0.22	-0.19	-0.08	0.24	0.82	1.45	0.97	1.17	1.61	1.39	1.26	1.54	3.30	1.91	2.31	2.13
Punjab																
Average Cost of Supply (ps./unit)	24.54	20.58	24.69	26.29	24.78	29.84	36.46	39.29	44.43	48.54	57	60.45	66.48	83.89	98.4	102.76
Average Rate of Realisation (Agricultural)(ps./unit)	13.36	14.8	17.49	13.24	13.79	13.4	14.6	16.4	16	17.8	18.54	16.52	9.02	8.84	9.18	8.4
% of Agricultural Sales to Total Sales	30.25	27.42	29.02	30.34	34.25	37.05	35.33	33.03	33.75	31.51	33.54	33.09	36.34	41.47	39.44	38.96
Drag Factor	13.78	7.70	8.46	15.06	15.19	20.41	21.18	19.24	21.60	19.96	22.63	24.05	31.41	37.10	35.76	35.78
Rajasthan																
Average Cost of Supply (ps./unit)	23.85	22.79	24.83	30.82	29.95	30.94	39.12	43.79	54.02	61.5	67.58	76.38	77.04	93.95	92.42	97.91
Average Rate of Realisation (Agricultural)(ps./unit)	4.64	28.5	26.98	27.23	29.79	19.22	19.19	19.55	20.35	19.19	19.27	24.77	27.46	22.4	29.46	29.46
% of Agricultural Sales to Total Sales	16.94	14.79	15.87	18.14	15.23	23.62	28.12	27.93	31.88	28.97	29.91	28.59	27.07	32.25	28.29	28.79
Drag Factor	13.64	-3.71	-1.37	2.11	0.08	8.95	14.33	15.46	19.87	19.93	21.38	19.32	17.42	24.56	19.27	20.13
Tamil Nadu																
Average Cost of Supply (ps./unit)	24.57	24.97	32.05	29.42	30.48	34.54	43.82	50.39	63.68	73.12	64.24	76.42	76.78	84.72	86.14	97.86
Average Rate of Realisation (Agricultural)(ps./unit)	13.35	17.21	20.9	20.08	16.46	16.4	16.34	15.12	14.25	14.25	12.24	11.2	11.55	11.78	11.2	11.26
% of Agricultural Sales to Total Sales	32.77	26.33	25.76	23.89	25.36	27.12	27.53	25.77	26.37	27.34	22.41	26.99	26.53	24.92	26.48	25.4
Drag Factor	14.96	8.18	8.96	7.58	11.66	14.24	17.26	18.04	20.47	22.01	18.14	23.03	22.54	21.45	23.04	22.48
Uttar Pradesh																
Average Cost of Supply (ps./unit)	33.94	34.76	32.51	39.31	40.19	48.87	56.33	64.37	67.11	74.39	79.68	85.64	85.51	88.28	103.69	102.38
Average Rate of Realisation (Agricultural)(ps./unit)	24.37	25.82	22.18	18.69	18.8	18.7	18.3	22	22.5	27.5	27.87	27.85	27.28	24.57	22.67	22.67
% of Agricultural Sales to Total Sales	24.51	27.12	24.82	29.25	29.91	32.03	34.15	32.63	33.08	32.38	32.36	31.32	36.16	35.41	39.13	39.47
Drag Factor	6.91	6.98	7.89	15.34	15.92	19.77	23.06	21.48	21.99	20.41	21.04	21.13	24.62	25.55	30.57	30.73
West Bengal																
Average Cost of Supply (ps./unit)	17.62	25.67	25.82	29.86	32.79	39.9	49	62	72.48	91.26	88.31	100.21	104.06	106.62	123.92	120.93
Average Rate of Realisation (Agricultural)(ps./unit)	20	25	29.41	29.82	29.44	32.7	33.47	51.7	39.35	35	33.28	35.3	36.4	24.8	26.86	25.58
% of Agricultural Sales to Total Sales	1.65	2.4	2.38	2.01	2.36	2.51	2.44	1.53	2.71	2.62	3.41	3.29	3.34	5	7.27	8.05
Drag Factor	-0.22	0.06	-0.33	0.00	0.24	0.45	0.77	0.25	1.24	1.62	2.12	2.13	2.17	3.84	5.69	6.35
Total Average																
Average Cost of Supply (ps./unit)	22.52	24.01	26.17	28.07	30.45	35.34	41.9	47.59	54.78	61.77	65.07	74.59	80.37	88.96	94.2	96.28
Average Rate of Realisation (Agricultural)(ps./unit)	18	21.15	21.74	20.63	18.74	18.24	18.84	20.19	19.41	20.48	18.64	18.15	17.7	14.89	15.7	16.13
% of Agricultural Sales to Total Sales	16.5	15.92	16.37	15.44	16.16	18.5	18.74	17.8	19.22	18.65	20.1	20.48	22.85	25.06	24.42	24.43
Drag Factor	3.31	1.90	2.77	4.09	6.21	8.95	10.31	10.25	12.41	12.47	14.34	15.50	17.82	20.87	20.35	20.34

SOURCE : Report of the Working Group for Strengthening Finances of SEBs.

ESTIMATES OF CONSUMPTION BY AGRICULTURAL SECTOR

(SELECTED STATES ONLY)

STATE	U. P. 1986-87	RAJASTHAN 1986-87	PUNJAB 1987-88	HARYANA 1987-88
I. Sales as per audited accounts (MKWH)	4937.8	1580	4244.14	2176.28
II. Estimate as per Agricultural connected load. 1/				
a) Agricultural connected load KW	2428004	1374852	1734127	1453321
b) Average capacity per Pump set (KW)	4.26	4.63	3.38	4.46
c) Average consumption per pumpset (Kwh)	8692	5350	8259	6682
d) Total consumption (MKwh)	4953.7	1588.23	4242.42	2176.28
III. Estimate as per irrigation of cultivated land 2/				
a) Total cropped area (area sown more than once is accordingly added as many times) Hc	25198103	17640317	7217000	4685754
b) Area irrigated by tubewells.	9342102	1193762	5146900	2658800
c) Estimated electricity consumption [5b (acres) x 3.7 kw. x 5 hrs] Mkwh 3/	2160.36	276.05	1190.22	614.84
IV. Average cost of supply paisa/Kwh.	82.1	69.84	67.57	92.95
V.				
a) Excess Estimate of Agricultural sales II [I - III(c)]	2777.4	1304	3054	1562
b) Net indirect savings [IV x V(a)] Rs.million	2280.24	910.71	2063.58	1451.87

A sample calculation of number of hours of operation of electric pump-sets (per crops)

a.	Engine BHP	*	7.28
b.	BHP	*	6.06
c.	Water HP	*	0.97
d.	Discharge (litres/sec)	*	7.327
e.	Requirement of water for irrigating one hectare of land once		2.25 lakhs litres
f.	No. of hours of operation for irrigating one hectare once		8.5 hours
g.	Electricity consumption for the cropping season (kwh) per hectare for irrigating 5 times		270 kwh.
h.	Yield per hectare wheat (UP 86-87) (Punjab 87-88)		26 quintals 34 quintals
i.	Electricity Consumption per quintal wheat (U.P.) (Punjab)		10.4 7.0

* Based on a study of Bundelkhand Zone of U.P. by S. Ramesh & K. Thukral (International Energy Journal Vol.10 No.1 June 1988)

NOTE

b. Engine BHP = 1.2 BHP

c. Water HP = e. BHP where e = 0.16 is the combined efficiency of pump and transmission

d. Discharge (litres/sec) = (Water HP x 76)/h where h=10 metres (total head). The total - head in U.P. is 16 metres in Hilly Zone, 14 metres in Western Zone, 12 metres in Central Zone and 10 metres in both Eastern and Bundelkhand Zone.

e. An average estimate for Western U.P., Haryana and Punjab

POWER SECTOR IN SAARC COUNTRIES

Bangladesh
Bhutan
India
Maldives
Nepal
Pakistan
Sri Lanka

Bhavna Bhatia

Bhaskar Natarajan

for presentation at the training programme on
"Planning for the Power Sector",
9-13 December 1991,
Hotel Mughal Sheraton, Agra.

BANGLADESH

Institutions and organisational structure

The Bangladesh Power Development Board (BPDB), a statutory government entity formed in 1972, is responsible for planning, construction and operation of power generation, transmission and distribution in all areas except some rural areas which are instead served by the Rural Electrification Board (REB). REB was created in 1977 and it distributes power in rural areas through a system of cooperatives called Palli Biduyat Samites (PBSs).

The Ministry of Energy and Mineral Resources, in consultation with the Ministry of Finance and the Planning Commission, formulates power sector policies, allocates resources to the sector, approves all major investment decisions, and determines tariff levels.

Supply system

Due to Brahmaputra - Jamuna river, Bangladesh electricity system has developed in two separate parts-in the east and west zone. The east zone is characterized by gas based power plants while the plants in the west zone use costly imported fuel oil. The entire hydroelectric capacity is located in east zone. Also, there are a large number of small stations scattered all over the country ranging in size from 50-12,000 kW, mostly consisting of steam, diesel and gas turbines. The total installed capacity in the country has grown from 547 MW in FY1971 to 813 MW in FY1981 and further to 2365 MW in FY1989. Of the total installed capacity gas based power plants have accounted for nearly 55 percent, and there share has been on an increase since mid 80's. During FY1989 71 percent of the total installed capacity in Bangladesh was gas based. The power systems in the two zones were interconnected in December 1982, by a 230 kV double circuit transmission line. This has led to a reduction in total system generating costs by substituting oil - based generation in the west by natural gas based generation in the east, as well as improved the overall power supply reliability. Table 1 gives the trends in installed capacity, gross generation and system losses in Bangladesh.

During the period FY1976 to FY1989, gross energy generation in Bangladesh has grown at an average rate of growth of 13.1 percent per annum. Share of hydro-electricity in total electricity generated has declined from 26.8 percent in FY1976 to 12.9 percent in FY1989 and that of diesel and coal based power has declined from 32.6 percent to 8.2 percent during the same period. On the other hand share of gas based electricity has been almost doubled from 41 percent in FY1976 to 79 percent in FY1989.

System losses in Bangladesh have been very high. During FY1980, system losses were approximately 40 percent of gross

generation; it declined to about 31 percent in FY1986. However, in the following two years the losses have gone up once again being 37.6 percent in FY1987 and 42.4 percent in FY1989. It needs to be pointed

Table 1: Trends in installed capacity, electricity generation and system losses of utilities in Bangladesh

Year	Hydro		Gas		Coal		Total capacity	Gross generation	System losses
	MW	%	MW	%	MW	%	MW	Mus	(%)
FY1975	80	12.0	371	55.6	216	32.4	667	1322	36.8
FY1980	80	9.7	426	51.8	316	38.4	833	2353	40.2
FY1981	80	9.8	426	52.4	307	37.8	813	2662	34.7
FY1983	130	14.1	481	52.4	308	33.5	919	3433	30.1
FY1984	130	11.6	577	51.5	414	36.9	1121	3966	31.8
FY1985	130	11.4	577	50.6	434	38.0	1141	4528	37.3
FY1986	130	11.1	633	54.1	408	34.8	1171	4800	31.1
FY1987	130	8.1	1069	66.5	408	25.4	1607	5587	37.6
FY1988	230	10.7	1468	68.5	448	20.8	2146	6541	42.4
FY1989	230	9.7	1678	70.9	457	19.4	2365	7114	

Source: Appraisal of Eighth Power Project in Bangladesh, ADB.

out that BPDB defines station service to include not only auxiliary consumption in power station, but also use in offices and residential colonies of the power station staff. Technical losses in distribution system are reported to be high due, in part, to inadequate investment in distribution facilities in addition to investments in transmission. Inadequate metering, improper billing and pilferage are the main causes of high level of non-technical losses.

Power market

During the period FY1975 to FY1988 peak demand and energy sales in Bangladesh has grown at an average annual growth of 13.1 percent and 12.3 percent respectively. Table 2 gives trends of growth of peak demand and energy sales in Bangladesh. There has been a structural change in the consumption pattern among different consumer categories. The share of domestic consumption has increased from 18.6 percent FY1983 to 23.5 percent in FY1988 and that of commercial sector has increased from 9.8 percent to 12 percent during this period (See Table 3 for details). As against this, the share of industries has gone down substantially from 67.4 percent in FY1983 to 8.8 percent in FY1988. An important feature of consumption of electric power in Bangladesh is that the share of agriculture is extremely small and has remained more or less constant during all these years.

Table 2: Trend in peak demand and energy sales in Bangladesh

Year ending on 30 June	Peak demand (MW)	Total sales (GWh)
FY1972	182	468
FY1973	221	623
FY1974	250	828
FY1975	266	835
FY1976	301	932
FY1977	342	1,013
FY1978	395	1 205
FY1979	437	1 381
FY1980	462	1 406
FY1981	545	1 740
FY1982	604	2 028
FY1983	709	2 399
FY1984	761	2 703
FY1985	887	2 841
FY1986	883	3 307
FY1987	1084	3 484
FY1988	1317	3 770

Source: Appraisal of the Eighth Power Project in Bangladesh, ADB

Table 3: Energy sales by consumer categories

Year	Domestic	Industry	Commercial	Agriculture	Others	Total
FY1983	445.4	1616.2	236.0	37.4	63.6	2398.6
	(18.6)	(67.4)	(9.8)	(1.5)	(2.7)	
FY1984	533.2	1726.7	286.8	50.0	106.7	2703.4
	(19.8)	(63.9)	(10.6)	(1.8)	(3.9)	
FY1985	659.6	1606.8	345.4	56.2	172.6	2840.6
	(23.2)	(56.5)	(12.2)	(2.0)	(6.1)	
FY1986	760.6	1723.7	533.1	51.1	238.3	3306.8
	(23.0)	(52.2)	(16.1)	(1.5)	(7.2)	
FY1987	902.3	1727.6	503.8	56.2	294.0	3483.9
	(25.9)	(49.6)	(14.5)	(1.6)	(8.4)	
FY1988	885.4	1840.4	617.1	62.9	364.2	3770.0
	(23.5)	(48.8)	(10.3)	(1.7)	(9.7)	

Figures in bracket indicate percent share
Source: Electricity Utilities Data Book for the Asian and Pacific Region, ADB.

Costs and revenues

As in the case with most developing countries, in BPDB also

the electricity tariffs are uneconomical. Cost of operations have been higher than revenues realized. BPDB has been incurring substantial losses and this has been attributed mainly due to the inability to keep tariffs at a level consistent with the costs. Another important factor contributing towards low level of revenue realization is high system losses.

In FY1978, net revenue losses were Tk 293.6 million and this amounted to 45 percent of the total revenue (this reduced to 27 percent in the following year). After a long period of operational deficits, BPDB showed a net operating income of Tk 561 million during FY1983, and the rate of return on the historical asset base was about 8.2 percent. This was partly due to an increase in the revenue income, as well as savings in the cost of fuel. Increase in revenue income was brought about from a 28 percent increase in the average tariff level and a reduction in system losses. Savings in fuel costs were possible due to the commissioning of east-west interconnection (there is wide variation in the BPDB's fuel costs in the east and west zones). This positive trend continued until FY1985. The share of fuel cost reduced from 61 percent in FY1982 to 54 percent in FY1985. In FY1986, there was a sudden jump in the fuel costs due to lower water availability in the hydropower plants. As a result of this BPDB incurred a net operating deficit of Tk 285 million (5 percent of the total revenues). Situation improved in the following year with BPDB earning a net operating income of Tk 556 million. Return on historical asset base in this year was 3.4 percent. Net operating income of Tk 812 million was realized in FY1988. Table 4 gives details of some of the important financial indicators for BPDB.

Table 4: Important financial indicators of BPDB

Ratio	FY1983	FY1984	FY1985	FY1986	FY1987
Operating ratio	0.82	0.87	0.94	1.03	0.93
Debt equity ratio	1.00	0.75	0.89	1.04	1.27
Debt service ratio	2.78	2.40	1.73	0.89	1.65
Self-financing ratio	0.25	0.18	0.15	0.07	0.13
Rate of return (%)	8.20	6.56	3.30	0	3.40

Source: Electric Utilities Data Book for the Asia and Pacific Region, ADB.

Tariffs

In recent years, BPDB has made serious efforts to simplify tariffs and relate them to the cost of supply. The BPDB's tariffs were raised by 38 percent in September 1979, by 40 percent in October 1980 and by a further 40 percent in July 1982. It is interesting to note that tariff revisions are carried out annually. The tariffs were increased by 3.2 percent in 1983, by 9.5 percent in March 1984, by 3.4 percent in December 1984 and by 16.4 percent in September 1985.

A new simplified set of tariffs was introduced in August 1987, where BPDB's average tariff rate was raised by 15 percent bringing it to about 70 percent of the economic cost of supply. The number of tariff categories were reduced from 18 to 10 and the sizes of the subsidized blocks of energy consumption of residential consumers were also reduced. In addition, a new two-part time-of-day tariffs for 33kV and 11kV consumers was introduced. Time-of-day tariffs for large low voltage consumers was also introduced. A comparison of tariff structure in force during eighties is made in Table 5.

Table 5: Comparison of electricity tariffs during eighties in Bangladesh

Consumer category	July 1982	September 1985	August 1987	July 1990
Domestic	0.50 (0-50 kWh)	1.00 (0-100 kWh)	1.25 (0-70 kWh)	1.55 (0-200 kwh)
	0.60 (51-250 kWh)	1.10 (101-400 kWh)	1.40 (71-200 kWh)	2.95 (201-600 kwh)
	0.70 (251-400 kWh)	2.75 (> 400 kWh)	2.85 (> 200 kWh)	3.85 (> 600 kwh)
	2.00 (>400 kWh)			
Agriculture	.50 (0-250 kWh)	1.37/kWh	1.70a	1.75
	1.00 (> 250 kWh)		1.35b	
			4.00c	
Small industry	1.50a	2.00a	2.30a	2.40a
	1.10b	1.95b	2.00b	2.10b
	4.00c	3.90c	4.25c	4.45c
Commercial consumers	1.40 (0-100 kWh)	2.20 (0-100)	2.80a	2.95a
		2.95 (> 100)		
	2.50 (> 100 kWh)		2.00b	2.15b
			5.40c	5.70c
HT-industries	1.55a	1.95a	N.A.	2.05a
(33 kV and upto	0.90/KVAMb	1.90b		1.70b
10 MW)	3.15/KVAMc	3.80c		3.80c

Note: a-All energy without time of day meter, b-Time of day off peak rate/kWh, c-Time of day peak rate/kWh

N.A. - Not available

REC also revised the tariffs for supplies to rural areas in May 1987. The electricity rates were increased by an average of 20 percent. Further, in July 1987, the tariffs were restructured to include (i) a new tariff category for high-voltage consumers; (ii) a time-of-day tariff for large low voltage consumers; and (iii) a three-block increasing tariff for residential consumers.

An important feature of BPDB tariff is that the fixed cost of power generation and supply is recovered through a service charge from each category. In addition to the energy charges, demand charge based on the sanctioned load is levied on all consumer categories except high-voltage bulk supply of electricity to REB/PBS, who in turn supply electricity to rural areas. Demand rate for supply at 6350/11000 volts is levied on the basis of maximum demand. BPDB has a fuel

adjustment clause to account for increase in fuel prices. This clause is applicable to all consumer categories. In order to encourage the consumers to maintain unity power factor as nearly as practicable, BPDB levies a penalty, on consumers whose power factor fall below 0.95.

Future outlook

Power and energy generation forecasts have been undertaken in the recent past by BPDB. During the period FY1990 to FY2000, the total generation is expected to grow at a compound annual growth rate of 6.1 percent. A high level of system losses has been a serious problem for BPDB since mid 70's BPDB has identified some steps to reduce their technical losses: (i) increase in investment in strengthening T&D system (ii) improved distribution planning (iii) reduction of 400 V line lengths (iv) further power factor improvements. It is expected that with successful implementation of these steps the losses will reduce to 28 percent by 2000 AD.

BHUTAN

Institutions and organisational structure

Power supply in Bhutan is the responsibility of Department of Power (DOP), which is a part of the Ministry of Trade and Industry. DOP looks after the generation, transmission, sub-transmission and distribution of electrical energy. DOP is the sole authority for supply and distribution of electricity in the country. DOP draws most of its electricity from Chukha Project Authority (CPA), which is responsible for the Chukha Hydro Power Project. In addition to DOP, there are also some private, independently operated generation and transforming facilities: Penden Cement, Gedu Wood Manufacturing Corporation and Bhutan Carbide and Chemicals Ltd.

Supply system

The country may be divided into three district zones based on power supply.

(i) The western zone, along the Thimpu - Phuntsholing axis, which began receiving power from Chukha during FY1987, and is entirely self sufficient with respect to its electrical energy needs.

(ii) The central zone, extending between Gaylegphug and Tongsa, which depends heavily on imports from the Assam State Electricity Board (ASEB) in India, because it has not yet developed any hydroelectric generation schemes.

(iii) The eastern zone, which is characterized by hydroelectric self-reliance in the north and imports from India in the south.

Power generating capacity in Bhutan includes 336 MW plant in Chukha, seven small sized hydro plants ranging from 300-1500 kW and 12 micro-hydro plants having a capacity from 10 to 80 kW. The total installed capacity increased from 20 MW in 1985 to 193.26 MW in 1986, primarily with the commissioning of first two units (2x84 MW) of the Chukha Hydro Project in the latter half of 1986. The third and the fourth units of Chukha were commissioned in the latter half of 1988. Trends in installed capacity in Bhutan is given in Table 1.

From 1979 to 1985, DOP's generation increased on an average rate of 4.7 percent per annum. In the same period imports from India increased sharply and total supply increased at an average rate of of 11 percent per annum. In 1986 DOP started to draw electricity from Chukha Hydro Project and DOP's own generation and electricity imports decreased. From 1985 to 1989, the total DOP supply went up from 19 GWh to 144 GWh. Out of the total supply of 144 GWh, in FY1989 as much as 95 percent was drawn from Chukha. Table 2 gives the summary of electricity generation and supply by DOP.

Table 1: Trends in installed capacity (MW)

Year	Hydro	Diesel	Total
FY1984	3.45	15.65	19.10
FY1985	3.46	16.70	20.16
FY1986	176.50	16.70	193.26
FY1987	341.56	13.00	354.56
FY1988	341.56	13.00	354.56
FY1989	341.56	13.00	354.56

Source: Energy Data Profile, DOP, Ministry of Trade & Industry, April 1991, Bhutan.

Table 2: Electricity generation and sales by DOP (Gwh)

	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
-Hydro	7.49	7.31	7.58	8.28	7.95	7.36	6.94	5.45	5.38	2.71	3.39
-Diesel	0.61	1.53	1.57	1.59	2.33	3.71	3.71	1.55	0.31	0.24	0.02
-Total	8.10	8.84	9.15	9.87	10.27	10.52	10.65	7.00	5.69	2.95	3.41
Drawn from Chukha								14.05	61.95	136.51	136.44
Import from India	1.95	2.46	3.20	4.51	4.89	5.15	8.14	3.45	3.67	3.52	4.09
Total supply	10.05	11.31	12.35	14.38	15.16	15.67	18.79	24.50	71.31	142.98	143.94
Losses	2.99	3.40	3.88	7.99	4.41	3.45	4.16	7.29	10.39	19.71	15.92
Total sales	7.05	7.90	8.47	9.39	10.75	12.22	14.63	17.21	60.93	123.27	128.02
Peak load (MW)	3.40	3.60	4.10	4.60	5.30	6.50	8.20	9.10	16.50	24.00	22.00
Losses (%)	29.80	30.10	31.40	34.70	29.10	22.00	22.10	29.80	14.60	13.80	11.10
Load factor	33.70	35.50	34.40	35.70	32.70	27.50	26.20	30.70	39.50	68.00	74.20

The percentage losses for the country as a whole have reduced to almost one third from 30 percent in 1979 to 11 percent in 1989. Improvement in the system losses was due largely to curtailed pilferage, through improvements in transmission and distribution networks and by implementing strict control procedures for meters. The load factor declined from 34 in 1979 to 26 in 1985 and thereafter it has been on an increase. The increase in load factor after 1986 may be attributed to the development of large evenly distributed industrial loads.

Power market

Energy sales by DOP increased on an average by 13.5 percent per annum over the period 1979-86, from 7.2 GWh to 17.2 GWh. In 1987, there was a sudden increase in sales to 60.9 GWh, due mainly to increased demand by the industrial sector. The peak load registered a similar pattern of growth. The average growth rate of peak load was

15 percent during the period 1979 to 1986 and during the period 1986 to 1989 it grew at a much faster rate of 34 per cent per annum (Refer Table 2 for details).

The consumer categorywise details of sales of electricity in Bhutan is given in Table 3. Over the ten year period from 1979 to 1989, sales to the household sector increased on an average by 13.5 percent per annum. The growth has been particularly strong since 1986. However, due to even stronger increase in industrial sales, the household share of total sales decreased from 45 percent in FY1979 to 9 percent in FY1989. In the last years the increase in household sales has been a result of an almost equal increase in the number of consumers and increase in sales per consumer. The number of household customers was 11333 in 1989, and the annual average sale per household was close to 100 kWh.

Table 3: Consumer categorywise energy sales in Bhutan (Gwh)

Year	Household	Industries	Commercial	Total
1979	3.200	0.737	3.034	6.971
	(45.9)	(10.6)	(43.5)	
1980	3.821	0.844	3.209	7.873
	(48.5)	(10.7)	(40.8)	
1981	4.016	1.132	3.278	8.435
	(47.7)	(13.4)	(38.9)	
1982	3.838	1.091	4.387	9.316
	(41.2)	(11.7)	(47.1)	
1983	4.151	1.256	5.285	10.693
	(38.8)	(11.7)	(49.5)	
1984	4.403	1.572	6.025	12.000
	(36.7)	(13.1)	(50.2)	
1985	4.523	1.945	8.168	14.640
	(30.9)	(13.3)	(55.8)	
1986	5.941	2.606	8.660	17.207
	(34.5)	(15.14)	(50.3)	
1987	9.932	38.720	11.723	60.375
	(16.5)	(64.13)	(19.4)	
1988	9.623	102.261	11.362	123.246
	(7.8)	(83.0)	(9.2)	
1989	11.333	103.275	13.407	128.015
	(8.9)	(80.7)	(10.5)	

1987 figures are for 15 months, 1/4/87 to 30/6/88
Figures in bracket are percentages
Source: Bhutan Power System Master Plan, Working Paper Power Market Forecast, May 1991.

Industrial sales accounted for 81 percent of total sales in 1989 up from 12 percent in 1979. The trend in the sales to the industrial sector has been dominated by the commissioning of a few large industrial plants in recent years. These are Bhutan Carbide &

Chemical Ltd., Penden Cement Authority, Gedu Wood Manufacturing Corporation, Bhutan Board Products Ltd. These four plants accounted for approximately 96 percent of the total sales to the industrial sector in 1989. Excluding the four large plants, sales to the remaining industrial sector increased by approximately 12 percent per annum from FY1979 to FY1989.

Electricity sales to commercial sector and government institutions increased at an average annual rate of 15 percent during the period 1979-89. Despite the high growth rate the share in total sales decreased from 43.5 percent to 10.5 percent during the 10 year period.

By the end of 1987, virtually all major towns and some large villages were supplied with electricity: 130 villages and 20 towns were electrified, compared to 105 and 18 respectively in 1982. Supplies to most rural areas are limited, because of difficulty of access and high capital investment required.

Costs and revenue

The DOP realized its first operating surplus during FY1987 due largely to increased availability of hydropower from the Chukha Project. The estimated cost of generation from the project is only Nu 0.10 per kWh, giving DOP an overall operating cost of Na 0.28 per KWh in FY1988. Total revenue earned by DOP during FY1988 was Nu 22.3 million at an average realization of Nu 0.37 per kWh.

Prior to FY 1988, energy charge was differentiated geographically based on the source and cost of supply. Areas supplied from local hydroelectric plants were charged less than areas supplied from a mix of local hydroelectric and diesel plants, and higher charges were assessed on areas supplied by power imports from India. Energy charges were further differentiated between consumer categories. Rates for residential users reflected the ability of households to pay; commercial rates were somewhat higher; and industrial rates were as low as possible to encourage growth in that sector.

This tariff structure was revised in 1988 and a uniform price of Nu 0.4 per kWh to all the categories of consumers was introduced. The tariff was further reduced to Nu 0.25/kWh in 1989. Tariff structure in force in FY1982 and the revised tariff structure of 1988 are compared in Table 4.

VIth five year plan 1987-92

The main emphasis during VI Five year plan is on regional balance. A substantial investment was allocated for the rural electrification schemes. The plan proposes to cover at least 10,000 rural households through grid extension and establishment of micro hydro schemes, and installation of photo voltaic power. The share of rural electrification in total power sector outlay for VI Plan is 15

Table 4: Comparison of tariff structure

1982	1988
1. Geographically and consumer categorywise differentiated energy charges	1. Uniform energy charge
2. Charges for new connections in urban areas assessed according to the actual cost of servicing a new subscriber	2. No charge
3. Subscribers in rural areas exempt from connection charges	3. Only first 50 subscribers in rural areas exempt from connection charges
4. Monthly meter charge	4. No meter charge
5. Demand charge for bulk consumers	5. No demand charge

Source: PUD Book.

percent. At the same time investments in the urban areas to cater to increase utilization has also been proposed. Furthermore, concerted efforts will be made in the investigations and studies for major hydro-electric schemes in large river basins. In 1990, a twenty year Power System Master Plan for hydropower development has been launched by DOP. Table 5 gives the function wise breakup of power sector outlay for VI Plan.

Table 5: Power sector outlay - 6th plan

Scheme	1987-88	1988-89	1989-90	1990-91	1991-92	Total
Generation	9.000	164.000	247.000	110.000	70.000	600.000
HV transmission	3.000	0.000	17.000	70.000	49.000	139.000
Subtransmission & distribution	69.825	47.207	32.806	27.820	13.844	183.502
Rural electrification	29.373	41.025	32.806	45.394	40.190	188.242
Hydrological investigation	11.450	12.200	13.400	11.400	9.900	58.350
Central establishment	23.259	17.024	14.975	11.499	12.049	78.806
	137.907	281.460	357.440	276.113	194.983	1247.900

Source: Sixth Five Year Plan 1987-92, Planning Commission, Royal Government of Bhutan.

Bhutan's power system master plan has forecasted the total sales in DOP system to stand at 718 GWh in 2010, up from 128 GWh in 1989, i.e., an average annual increase of 8.6 percent over the forecast

period. The growth in sales is expected lower in the latter part of the period than during the first years. Although loss factors are assumed to gradually decrease, the total electricity requirement is expected increase by approximately the same percentage as the sales, due to decrease in industrial share of total sales. It is forecasted that total requirement will increase from 144 GWh in 1989 to 868 GWh in 2010. The system peak load which stood at approximately 25 MW in 1989, is forecasted to reach 153 MW in year 2010.

Table : Forecast of energy sales requirement peak load

Year	Sales (GWh)	Requirement (GWh)	Peak load (MW)
1989	128	144	25
1995	365	444	78
2000	548	671	118
2005	613	747	131
2010	718	869	153

Source: Bhutan Power System Master Plan.

Household sales are forecasted to increase by 12.5 percent over the forecast period, while industrial sales and commercial and government institution sales are assumed to increase by 7.8 percent and 9.2 percent respectively. The industry's share of total sales is estimated to decrease from 81 percent in FY1989 to 70 percent in FY2010, whereas the household sector's share is go up from 9 percent in FY1989 to 18 percent in FY2010. The commerce and government institution's share is expected to remain more or less unchanged at 11-12 percent.

INDIA

Organisation of the power sector

Prior to 1947, the supply of power was a predominantly commercial venture undertaken by privately owned utilities located in and around urban areas. The Electricity (Supply) Act, 1948, provided for the creation of State Electricity Board (SEBs), charged with the responsibility of generation, transmission and distribution of electricity in the State. The SEBs began operations in the mid-1950s, and by the late 1950's they serviced all major states. In smaller states not yet serviced by an SEB, electricity supply is the responsibility of the Government Electricity Departments. There are today 18 SEBs, 13 State/ Union Territory Electricity Departments and one Municipal Corporation in the 25 states and 7 union territories of India. In several states, licensees already engaged in generation and distribution of power were allowed to continue in business so long as their licenses were valid. Today, there are three utilities in the power sector which are engaged in power generation and distribution - Tata Electric Company, Calcutta Electricity Supply Company and Ahmedabad Electric Company.

The Act, also envisaged the creation of a central body, the Central Electricity Authority (CEA), with the responsibility of evolving a national power policy as well as coordinating the activities of the power sector in the country. The CEA has also been given the responsibility of providing technical advice to the SEBs regarding the formulation of projects for power development. All power projects costing more than Rs 50 million require the concurrence of CEA.

In addition to the SEBs, the Central Government plays a direct role in the power programme through (a) Damodar Valley Corporation (b) Neyveli Lignite Corporation and (c) Nuclear Power Projects. By an amendment to the Act in 1976, the National Thermal Power Corporation (NTPC), the National Hydro-power Corporation (NHPC) and North Eastern Electric Power Corporation (NEEPCO) were set up to construct power stations, exploit economies of scale and cater to the needs of several states. These corporations generate and sell electricity to SEBs and EDs according to their allocated shares.

Besides, these central government established corporations, some of the state governments also established power corporations to be responsible for power generation. However, in most of the states these corporations were set up to construct the power plant, which was on completion handed over to the respective SEB for generation and distribution.

Due to diversity in consumption patterns between states as well as variations in generation mix, transfer of power between the states takes place during different times of the day as and when the need arises. The need to promote regional utilisation of scarce national resources was strongly felt. Keeping this in view, in 1963, the country was divided into five regions and Regional Electricity

Boards (REBs) as associations of constituent SEBs and other power utilities in the respective regions, were created through Central Government Resolutions. REBs coordinate SEBs generation schedules and maintenance programmes, monitor systems operations and help arrange inter-state power exchanges.

The overall responsibility of power development lies with Department of Power (DOP) under the Central Ministry of Energy. DOP is responsible for formulating policy and plans for the power development, processing power projects for investment decisions, training and human resource development and administrating any legislation pertaining to power generation and supply. The CEA is administratively under the DOP as are the central sector power corporations of NTPC, NHPC, NEEPCO, the joint corporations of DVC, BBMB and the financing organisations, Rural Electrification Corporation (REC) and Power Finance Corporation (PFC). REC is a specialised development financial institution at the national level, set up in 1969 with the objective of financing and monitoring rural electrification programmes. PFC has been established by the government to assist high priority power projects by insulating them from the budgetary constraints of the central and state governments.

DOP provides the linkage with the other Ministries/ Departments in the Central Government, Planning Commission and the State Governments. The Planning Commission is responsible for incorporating plans and programmes for economic development.

Supply system

The total installed power generating capacity in India increased from 2301 MW at the end of 1950 to about 73,000 MW in March 1991, at an average annual rate of 8.7 percent per annum. The share of the public utilities capacity in the total increased from around 37 percent to about 90 percent during the same period. At the end of FY 1990, the total installed utility capacity was about 67,805 MW; of which 19324 MW (28.5 percent) was hydro, 1700 MW (2.5 percent) was nuclear and the remaining 46781 MW (69 percent) was thermal (coal and lignite fired steam thermal capacity, gas turbines and diesel engines). Trend in installed capacity in utilities since 1950 is shown in Table 1.

More than 50 percent of this total installed capacity has been added during the past ten years alone. Utility capacity more than doubled from about 30,200 MW in March 1981 to over 67,800 MW in March 1991. During this time period, the share of installed hydro capacity reduced from 39 percent to 29 percent, and that of thermal increased from 58 percent to 69 percent. The share of nuclear capacity has remained almost unchanged at 2.5 - 3 percent level. India has also expanded its small hydro power capacity over the years. As on May 1989, 111 micro/mini/ small hydro stations with aggregate capacity of 201 are in operation in the country.

In line with additions to installed capacity, gross generation in public utilities also has increased rapidly, from 5107 MUs in 1950

Table 1: Installed capacity in utilities

(MW)

Year	Hydro	(%)	Thermal	(%)	Nuclear	(%)	Total
FY1950	559.29	32.65	1153.23	67.34			1712.52
FY1960	1916.66	41.19	2736.39	58.80			4653.05
FY1965	4123.74	45.68	4903.28	54.31			9027.02
FY1970	6383.23	43.39	7905.73	53.74	420.00	2.85	14708.95
FY1975	8463.60	42.07	11013.46	54.74	640.00	3.18	20117.06
FY1980	11791.22	39.02	17563.43	58.12	860.00	2.84	30216.68
FY1985	15471.60	33.08	29967.43	64.07	1330.00	2.84	46769.86
FY1986	16195.64	32.80	31740.22	64.42	1330.00	2.69	49265.03
FY1987	17215.09	31.70	35650.22	65.65	1330.00	2.44	5425.86
FY1988	17586.40	29.51	40671.50	68.25	1330.00	2.23	59587.90
FY1990	19324.42	28.5	46785.55	69.0	1695.00	2.50	67804.97

to nearly 270,000 MUs in FY 1990, at an annual average growth rate of 10.4 percent. During this period hydro electricity generation has registered an annual growth rate of 8.4 percent per annum where as the power generation from thermal power plants has grown at a much faster rate of 11.5 percent per annum. The compound annual growth rate of hydroelectricity fell from 12.4 percent during the sixties to 6.3 percent in seventies and further to 3.2 percent in eighties.

The ratio of hydro to thermal generation which varied between 1:1 to 1:1.25 during the 1950s and 1960s, began to decline steadily during 1970s. In FY 1990, hydro-thermal generation mix was 1:3. The gross nuclear power generation in the country has increased from 2300 MUs in FY1980 to 7020 MUs in FY 1990, at an annual growth rate of 8.9 percent. In FY1990, gross nuclear power in the country accounted for 2.6 percent of the total utility generation (refer Table 2 for details).

Losses in the T & D network continue to be a matter of serious concern. T & D losses have actually increased over the years from 17.5 percent in FY1970 to 21.7 percent in FY1985. Between FY1982 and FY1989 average T & D losses of all the country's utilities has shown no decline and has remained, slightly over 21 percent of the total energy handled. Table 3 gives T & D losses in the country's utilities. Owing to significant differences in plant mix, length of the T & D lines, topography, load utilities, interregional and intraregional variations in the (All India Utilities) system losses are wide. During FY1987, losses were highest in the North Eastern region (27.6 percent) and lowest in the Western region (19.38 percent).

The extensive losses in the T&D networks result from both technical and non-technical factors. To accommodate the massive rural electrification programmes, utilities extended their T&D lines over long distances to areas of low load density. However, subsequent investment in T&D was limited and has become a major factor in the high level of technical losses. Accurate assessments of the extent

Table 2: Trends in energy generation in utilities

GWh

Year	Hydro	(%)	Thermal	(%)	Nuclear	(%)	Total
FY1950	2519.77	49.34	2586.93	50.65			5106.70
FY1960	7836.58	46.26	9100.43	53.73			16937.01
FY1965	15224.97	46.15	17765.02	53.84			32990.12
FY1970	25248.24	45.22	28162.02	50.44	2417.38	4.33	55827.64
FY1975	33301.77	42.03	43502.64	54.65	2626.10	3.31	79230.51
FY1980	46541.76	41.98	61300.86	55.30	3001.34	2.70	110843.90
FY1981							
FY1982							
FY1983							
FY1984							
FY1985	51020.78	29.95	114347.47	67.12	4981.88	2.93	170350.13
FY1986(a)	53851.18	28.67	128925.50	68.65	5021.94	2.67	187798.60
FY1987(b)	47396.00	23.47	149469.00	74.03	5029.00	2.49	201894.00
FY1988(b)	57742.00	26.13	157436.00	71.24	5800.00	2.62	269989
FY1989							
FY1990	63987.39	23.7	198981.89	73.70	7019.72	2.60	269989

(a) Provision (b) Tentative

Source: CEA, General Review, op. cit Ref. Table 2.3.1;
CMIE, op. cit Ref. Table 2.3.4.

Table 3: Transmission and distribution losses - (including unaccounted commercial losses in utilities)

Year	T&D losses (%)	Year	T&D losses (%)
FY1970	17.50	FY1986	21.74
FY1980	20.56	FY1987	22.48
FY1981	20.71	FY1988	23.25
FY1982	21.14	FY1989	21.90
FY1984	21.47	FY1990	20.45
FY1985	21.74		

Source: Various issues of Public Electricity Supply General Review, CEA Annual report on the working of State Electricity Boards and Electricity Departments, Planning Commission, September 1990.

of nontechnical losses are not made by most utilities in India because of the absence of metering facilities, faulty meters as well as theft and pilferage of power.

The importance of reducing system losses is recognized and efforts to control both technical and non technical losses do occur.

These include developing schemes for system improvement, strengthening and modernizing urban distribution systems and conducting energy audits in T&D systems.

Power market

Electricity consumption in the country has grown at an annual compound rate of 9.1 percent during the period 1950-51 to 1988-89. The per capita consumption of electricity which was only 15 units in 1950 has grown to 230 units in 1989-90. As for the composition of sales to different categories of consumers there has been a marked increase in the share of electricity consumed by the agricultural sector: from 4.2 percent in FY1950 to 24 percent in FY1989. The share of industries has reduced from 63.8 percent in FY1950 to 41 percent in 1989-90. The share of domestic sector has increased marginally whereas that of the commercial sector has declined marginally. Table 4 gives details of the share of electricity consumption by different consumer categories.

Table 4: Sectoral shares in electricity consumption - percent

Year	Domestic	Commercial	Industry	Agriculture	Others
1950-51	12.4	6.9	63.8	4.2	12.8
1960-61	10.7	6.1	69.4	6.0	7.8
1965-66	8.8	6.2	70.6	7.1	7.3
1970-71	8.8	5.9	67.6	10.2	7.5
1975-76	9.7	5.8	63.4	14.5	7.6
1980-81	11.2	5.7	58.4	17.6	7.1
1985-86	14.0	5.9	54.5	19.1	6.5
1988-89	13.0	5.0	40.0	25.0	17.0
1989-90	14.0	5.0	41.0	24.0	15.0

Source: (1) Various issues of economic survey, GOI.
(2) Annual Report on the Working of SEBs and Electricity Departments, September 1990.

The peak load reached during the FY1988 was 34779 MW. This should be viewed against the peak loads of 9743 MW in FY1970 and 19089 MW in FY 1980. The average growth rate of peak load was 8.4 percent compounded for the period 1960-61 to 1988-89. Growth in peak load has been highest in Northereastern region (13.9 percent compounded annually) and lowest in Eastern region (5.2 percent compounded annually). Average peak load growth rate for Northern, Western and Sourthern region has been 9.8 percent, 8.8 percent and 9.1 percent respectively during the same period (refer Table 5 for details). These figures of peak demand, however, should not be considered as indicative of the actual situation in the country mainly because peak demands in almost all the SEBs have been suppressed due to power shortages. The convenience with which electricity can be used and the low prices charged by the SEBs (particularly to agriculture and

domestic consumers) have encouraged demand to grow at a phenomenal rate. On the other hand, because of financial constraints and long gestation period of power projects, the supply of electricity has not been able to keep pace with the rapidly increasing demand. The power supply position in the country has moved from a power surplus state in the early sixties to a deficit one from the mid-seventies onwards. During the last year of the VII plan, the overall energy shortages in the country was 7.9 percent and peak power shortage was 16.7 percent. Regionwise power supply position in 1989-90 is given in Table 6.

Table 5: Growth in peak load

(MW)

Region	1960-61 (a)	1970-71 (b)	1980-81 (c)	1985-86 (d)	1988-89 (e)	1989-90 (f)*	1990-91 (g)*
Northern	760	2647	5883	7896	10481	13172	14109
Western	1013	2565	5383	7651	10632	11564	12391
Southern	773	2663	4909	7135	8856	10748	11560
Eastern	1029	1788	2706	3548	4260	5519	17863
N-Eastern	14	80	208	413	540	633	695
All India	3551	9743	19089	26951	34779	41649	56633

*Provisional
Source: (1) (a)-(c) from TEDDY
(2) (d)-(g) from 14th Electric Power Survey
Note: The all-India peak is the arithmetic addition of regional peak demand.

Table 6: Power supply position at the end of VII plan (1989-90)

Region	Energy shortages (%)	Peak shortages (%)
Northern	5.3	9.6
Western	2.6	15.3
Southern	18.3	23.0
Eastern	15.0	22.0
N-Eastern	3.0	0.3
All India	7.9	16.7

Source: "Supply Options for the Power Sector in the 8th and 9th Plan", by R.N. Srivastava and D.S. Arora, CEA.

Tariffs

Electricity pricing in India is the responsibility of State Electricity Boards. While SEBs set tariffs within each state, they consult their respective state governments when fixing or raising their tariffs. Thus tariffs generally represent a compromise between

the financial objectives of the SEB and the state government with the structure determined by socio-political criteria, especially the perceived ability of different consumer groups to pay.

The tariffs are to be primarily based on considerations contained in the section 23 of the Indian Electricity Act 1910, and section 40 and 59 of the Electricity (Supply), Act 1948. The Act stipulated that tariffs assessed by the SEBs should meet all operating costs and capital charges. The Act was amended in 1978 to make SEBs commercially viable and to earn a net return on investment as specified. Another amendment to the Act in 1980 fixed the net rate of return to 3 percent on the net assets as at the beginning of the financial year.

However, in practise, none of the state governments impose a mandatory rate of return on the SEBs. Rather, the emphasis is on providing power for industrial and agricultural development at affordable rates. The agricultural sector heavily subsidized in most of the utilities. It is evident from the Table 7 that average revenue realized from agriculture and domestic sector was less than the average cost of generation and supply in all the SEBs. Industrial and commercial consumers are often charged high tariffs to cross-subsidize the agriculture and domestic consumers. In spite of this the per unit average revenue realized is less than the average cost of generation and supply in most of the SEBs resulting in high commercial losses (refer Table 7 for details).

Table 7: Average cost of electricity generation and supply and average rate of realisation in major states: 1988-89

State	Avg. cost of generation and supply	Avg. rate of realisation					Overall average realisation
		Domestic	Comm.	Agri*	LT-industry	HT-industry	
APSEB	65.4	52.3	114.4	4.5	111.4	94.9	60.8
ASEB	257.0	60.0	110.0	50.0	62.0	87.0	91.9
BSEB	149.2	57.3	94.6	9.4	171.2	132.5	93.5
GEB	102.5	67.8	67.8	24.8	113.8	116.2	82.9
HSEB	81.2	56.0	116.0	30.0	100.0	109.0	59.8
HPSEB	91.0	42.5	82.5	20.0	71.6	71.6	56.6
J&K	118.4	30.0	75.0	10.0	40.0	--	40.9
KEB	74.6	63.0	162.3	11.6	103.3	90.1	72.6
KSEB	66.6	48.7	78.0	22.0	60.0	57.9	56.3
MPEB	83.6	27.6	100.1	23.2	87.0	94.3	73.5
MSEB	87.9	47.0	89.0	9.0	76.0	118.0	80.0
MEGHALAYA	99.9	44.4	68.0	21.0	55.0	55.0	50.0
OSEB	66.2	44.0	92.0	22.1	53.3	65.9	65.6
PSEB	97.9	67.9	95.4	8.4	68.8	61.3	44.0
RSEB	98.5	58.2	107.4	29.5	83.7	91.8	81.1
TNEB	89.6	52.1	106.0	11.2	98.0	85.0	63.7
UPSEB	99.8	65.5	85.1	22.7	103.0	114.9	68.0
WBSEB	123.5	58.5	102.0	25.6	77.8	130.1	95.2

Source: (Reference no. [5])

The economic price of electricity should be determined on the basis of long run marginal cost of supplying electricity for different end uses. Some SEBs have initiated marginal cost based tariff studies although in implementation they have generally lagged behind. Table 8 compares the LRMC based tariffs and average revenue realized in some of the SEBs. Except for the HT-industries, LRMC based tariffs for other consumer categories are far below the respective average revenue realized in all the states. The extent of subsidy to agriculture and domestic consumers is evident from the Table 8.

Tariff structures and levels in nearly all states need to be rationalized for more efficient performance by the power sector. Tariff levels should gradually move towards recovering long run marginal costs. Tariffs based on time-of-day would help in reducing consumption during peak hours and encourage consumption during off-peak hours. The SEBs, to begin with, should introduce this in the case of HT-industrial consumers, on experimental basis. A beginning has been made by GEB, TNEB and MSEB.

Table 8: Comparison of LRMC based tariff and average revenue realized (in 1987-88)

	Domestic	Commercial	LT-industry	Agriculture	HT-industry
HSEB	1.11 (0.42)	1.19 (0.82)	1.37 (0.87)	1.03 (0.17)	0.82 (0.98)
MSEB	1.00 (0.47)	1.09 (0.89)	0.89 (0.75)	0.92 (0.09)	0.66 (1.10)
GEB	1.23 (0.28)	1.29 (0.68)	0.97 (1.07)	1.02 (0.22)	0.69 (1.10)
MPEB	1.04 (0.28)	1.05 (1.00)	1.12 (0.87)	--	--
TNEB	1.23 (0.59)	1.05 (0.96)	1.64 (0.87)	1.24 (0.12)	0.85 (0.87)

Note: Figures in bracket are average revenues realized in 1987-88

Source: TERI Report.

Future issues facing the power sector

According to the report of the Thirteenth Annual Power Survey Committee, it is estimated that, on an all-India basis, peak demand in FY1994 will be of the order of about 73,000 MW and the energy requirement will be of the order of about 385 billion units. Capacity additions to the tune of 38,000 MW was envisaged during the VIII plan. However, even with these additions to capacity, a peak load deficit of 12679 MW and an energy deficit of 736 MU on an all-India basis was expected. Table 9 gives the regionwise estimates of the peak and energy deficits in FY1994. The largest of 38,000 MW is scaled down to 27,000 MW and thus the deficits will increase further.

Table 9: Power supply projections for FY1994

Region	Energy shortages (MUs)	Peak shortages (MW)
Northern	-6216	-4338
Western	-3516	-3528
Southern	-17931	-3868
Eastern	+2997	-1181
N-Eastern	+4924	+273
Andaman and Nicobar Islands	+52	+40
Total	-7362	-12679

Source: Seventh Plan Review and Eighth Plan Issues and Options, Bahadurchand, Chairman, CEA, January 1989.

Plan allocation for the power sector has been between 17 - 18 percent of the total plan outlay. In absolute terms, the outlay for the power sector has been doubling every five years. In spite of this, availability of funds for the eighth plan is expected to be a major constraint. Considering the fact that demand shortages would continue into the Eighth plan, it is imperative that due emphasis is given to short-term measures that would release additional generation, which would help in reducing the demand - supply gap and also enable an improvement in the quality of electricity with some degree of reliability. Some of the short term options that need to be emphasized are (i) improving PLF of the thermal power stations (ii) direct participation of the SEBs in energy conservation and (iii) time-of-day tariffs for load management.

The Government of India in June 1990, announced a policy decision of encouraging private sector participation in the generation and distribution. The basic objective of this long awaited move is to bring in additional resources for investment in power supply facilities and thus at least partly make up the shortfalls. Further, private sector participation is expected to bring in increased efficiency in operations of the power sector. Among the incentives offered to private investors is the increased prescribed rate of return from 12 percent to 15 percent of the capital base, and allowing a debt/equity ratio of 4:1.

Energy from renewable energy technologies is an important area in the government's energy plan. The Department of Non-Conventional Energy Sources (DNES) which is a nodal agency for planning and implementing the renewable technology programme, in consultation with the state nodal agencies, has been making efforts to promote these technologies.

MALDIVES

Institutions and organisation structure

The generation, transmission and the distribution of electric power to whole of Maldives is the responsibility of the Maldives Electricity Board (MEB), established in 1968 under the provisions of a Parliamentary Act. While MEB is perceived by the Government as having a regulatory role for all public electricity generation, its direct responsibility for power supply is limited to five islands: Male', Gan, Thulusdhoo, Kulhudhuffushi and Thinadhoo. Electricity is generated and sold by private enterprise on approximately 100 islands, and is generated for its use by resort owners on 57 resort islands, and from facilities owned and operated by the Department of Civil Aviation on the airport island of Hulule. However, MEB is responsible for checking the safety standards in all the private generation and distribution facilities.

Supply system

The archipelagic nature of Maldives presents a difficult situation for the provision of electricity. The only practical way of providing electricity on the islands is through small independent systems each having its own small diesel generator. By far the largest single existing system is that of Male'. The system is served by a single diesel power station located in the heart of the capital, amidst residential and commercial properties. The total installed capacity in Male' has increased from 2.74 MW in FY1983 to 4.93 MW in FY1987. Total gross generation in FY1987 was 14.75 GWh, at an average capacity utilization factor on an installed capacity basis of 34.2 per cent Owing to the vintage of some of the diesel sets (which may be upto 25 years old) and engine cooling problems, six out of the twelve sets have been derated to 75 per cent of full capacity. The nominal firm capacity derived by assuming the largest unit to be outaged, and the remaining units to run at 85 per cent of full load, is therefore only 2.802 MW. Trends in installed capacity of MEB and gross generation are given in Table 1.

Table 1: Installed capacity and gross generation in MEB

Year	Installed capacity (MW)	Gross generation (GWh)
FY1983	2.74	7.40
FY1984	3.24	8.64
FY1985	3.24	10.29
FY1986	4.93	11.99
FY1987	4.93	14.76
FY1988	4.70	17.20

FY1983 - 1st January 1983 to 31st December 1983

The distribution system in Male' is compact - the total area is less than 200 hectares. The primary distribution network comprises 3.3 kV and 11 kV underground cables. Owing to their age and problems of overloading, the 3.3 kV cables are being replaced gradually by 11 kV cables.

Power market

Electricity sales have grown rapidly in Male'. During the eighties (1980 to 1989) the sales increased at an average annual compound growth rate of 19.3 per cent. There was a sharp increase (almost 27 percent) in electricity sales from 3.989 GWh in FY1981 to 5.054 GWh in FY1982. Peak load in Male' has grown at 17.6 per cent per annum - from 63 KW in FY1978 to 2730 KW in FY1987. It is estimated that delays in connecting new customers and peak period restrictions amount to a total suppressed demand of over 500 KW at peak time. The number of connections has grown from 3726 in FY1980 to 6338 in FY1989 - a rate of growth of 6.1 per cent per annum (Refer Table 2 for details). Growth in national income, increase in number of consumers and relatively low electricity tariff rates are the major factors influencing electricity sales growth in Male'. A substantial portion of the total electricity sales has been to residential and government consumers. In 1989, residential consumers accounted for 48.8 per cent of the total electricity sales, followed by government consumers whose share stood at 31.7 per cent. The manufacturing sector on Male' is relatively small accounting for only 2.4 per cent of energy sales in 1989. There is very little industrial activity on the other islands, except for a garment manufacturing factory in Gan.

Table 2 : Electricity sales and peak load in MEB

Year	Sales (GWh)	Peak load (KW)	T & D losses (%)	No. of consumers
1979	2.60	736	22.0	2917
1980	3.35	880	19.8	3726
1981	3.99	984	14.3	4064
1982	5.05	1100	10.2	4420
1983	6.35	1534	11.4	4696
1984	7.35	.1760	12.2	4996
1985	8.56	1990	14.1	5330
1986	10.21	2213	11.6	5655
1987	12.23	2730	14.3	6050
1988	14.45	-	13.12	6160
1989	16.43	-	-	6338

Transmission and distribution losses on Male', as a percentage of gross generation, has declined from 22 per cent in FY1979 to 13.2 per cent in FY1988. Since, service connection materials, cutouts and meters are procured by customers directly from the market, MEB cannot

exercise any quality control. Service lines are often substandard, resulting in high losses, and meters of doubtful performance result in poor metering accuracy. Auxiliary consumption has consistently accounted for 2.7 to 2.8 per cent of gross generation over the period 1979 to 1988.

Tariffs

The MEB applies separate tariffs for each of the three islands, on which it has direct responsibility. Since August 1984, electricity consumers in Male' have been classified into four categories: residential, government, commercial and manufacturing. Residential consumers are charged under a progressive block structure, while other consumers are charged a flat rate. Charges are levied on energy consumption alone - there is no monthly minimum charge. There is no differentiation among electricity consumers in the Thulusdhoo and Gan, where flat rate is levied. Adjustments to electricity tariffs require approval from the Office of the President.

Although no formal documentation of electricity pricing policy exists, changes in the structure and level of prices in recent years reflect a pricing policy supporting financial, economic and social objectives. Prices are designed to recover costs and mobilise revenues for the Government, ration the inadequate supply of power on Male' and increase energy conservation. Since August 1980 a regulation has been in force which prohibits the use of domestic electric appliances between 1830 and 2230 hours daily, which is time of system peak demand in Male'. In the Male' system, changes in tariff levels has favoured residential and Government consumers. Over the years, the blocks for tariffs for domestic consumers has been widened from time to time while retaining the block prices. The Government consumers earlier had block tariffs but now are charged at a flat rate which is less than the marginal price under the previous structure. These changes have significantly reduced the average revenues MEB recovers from these two consumer categories, who account for approximately 75 percent of total energy sales. Increases in the average price paid by commercial and manufacturing consumers, the recent withdrawal of a 20 percent discount offered by Government consumers, and increases in prices levied in other island systems have not fully offset these reductions, and as a result MEB's total average revenue has declined in both nominal and real terms in recent years.

Electricity prices in Maldives reflect a deliberate Government policy of allowing cross-subsidisation among both consumer groups and supply areas for balanced regional development. Consumers in Thulusdhoo and Gan, islands are subsidised by those on Male'. In 1986, average revenue per unit of electricity sales on Male' was 43 percent higher than that on the other two islands. A comparison of average prices paid by the different consumer groups in the Male' system and consumers on Thulusdhoo and Gan consumers is given in Table 3.

Table 3 : Average selling price by supply system/consumer category in 1986

Supply system	No.of consumers	Sales MKh	Sales %	Avg Sales	Avg prices Rf/KWh
<u>Male'</u>					
Residential	4395	5374	47	1223	1.61
Commercial --\	914	1691	15	2021	3.50
Manufacturing-/		156	1		3.50
Government	346	3090	27	8431	2.25
Total	5655	10311	90	1823	2.15
<u>Thulusdhoo</u>	a/	a/			
<u>Gan</u>	128	1197	10	9352	1.50b/
<u>All consumers</u>	5783	11508	100	1990	2.09

a/ Included under total for Male'
b/ Based on 1987 tariff
Source : Approval of Power System Development Project in Maldives, October 1987, ADB.

Financial performance

MEB's financial performance has been sound in recent years, due largely to its appropriate pricing policy. The overall price levels have been adequate to generate revenues sufficient to recover costs, to contribute to system development and to make contribution to the consolidated revenue of the Government.

Financial data for the period 1981-85 shows that all profitability and liquidity indicators are well above commercially accepted levels. MEB has financed about 72 percent of its development from its internal resources. However, since the take over of operations on Thulusdhoo (June 1984) and Gan (September 1985), MEB's performance has weakened as these supply systems incur losses, largely due to the low price levels (average revenue on these islands currently is about 43 percent lower than on Male and the high level of system losses (about 30 percent in 1986 in Gan). Further, increase in operating revenue (163 percent) has lagged behind the increase in operation expenses (186 percent) and this has resulted in decline in the profitability.

MEB's average selling price has fallen marginally in recent years. This may be attributed to many factors: (i) a changing consumer mix (proportion of sales to residential consumers, who are charged the lowest price, has increased significantly over the years); (ii) take over of the loss making operations on Thulusdhoo and Gan; and (iii) increase in fixed capital expenses. Nevertheless, profitability indicators have remained at satisfactory levels; the operating ratio has been equal to or below 0.8 in all years, and the

rate of return on historically valued average net fixed assets in service has averaged 41 percent. Some of the important financial indicators are summarized in Table 4.

Table 4: Financial indicators for Male Electricity Board

Year	Operating ratio	Debt equity ratio	Self financing ratio	ROR (%)
FY1982	0.80	0	na	27.60
FY1983	0.70	0	na	50.00
FY1984	0.70	0	na	54.53
FY1985	0.78	0.47	na	35.39
FY1986	0.77	0.39	16.93	35.37
FY1987	0.74	0.32	23.11	46.85
FY1988	0.76	0.77	19.34	52.14
FY1989a/	0.74	2.25	23.24	68.30
FY1990a/	0.73	2.58	44.95	38.06

a/ Estimated
Source: (i) Public Utility Data Book for the Asian and Pacific Region.
(ii) Appraisal of Power System Development Projects in Maldives, October 1987, ADB.

Load forecast

The load forecast for the Male' power supply system has been prepared by taking into consideration the expected growth in real GDP, an analysis of new consumers to be connected in the medium term, and a relaxation of the current ban on the use of electrical appliances during the time of system peak. Real GDP is expected to grow at about 8 percent per annum in the medium term. The rate of connecting new

Table 5: Forecast for load growth and sales in MEB

Year	No. of consumers	Max. demand (kw)	Sales (GWh)
FY1992	8328	5367	21.9
FY1993	8744	5935	24.2
FY1994	9182	6442	26.8
FY1995	9641	7125	29.7
FY1996	10123	7737	32.9
FY1997	10426	8399	36.4
FY1998	10739	8790	38.7
FY1999	11061	9202	41.3
FY2000	11393	9637	44.0

consumers is expected to be significantly less than in the past due to the fact that Male' is reaching its population saturation level. It is to be expected, that with rising incomes the intensity of electricity use will rise. In this context, electricity sales and peak load are projected to grow at an average of 9.1 percent and 7.6 percent respectively during the period 1992-2000.

NEPAL

Institutions and structure

The Ministry of Water Resources (MWR) is responsible for all public sector activities related to electricity supply, and exercises jurisdiction over Nepal Electricity Authority (NEA). The NEA was established on 15th August 1985, following the merger of the National Electricity Corporation, the Electricity Department of MWR, and the small Hydro Development Board. The NEA is responsible for the planning, construction, operation and maintenance of all generation, transmission and distribution facilities on the interconnected and main isolated system, except for the Marsyangdi hydroelectric project and Karnali project, for which special development boards are responsible. For small insulated micro-hydro power systems (usually 100 kW) the private sector and other non-governmental organisations are involved.

Supply System

Hydropower is Nepals' most abundant resources and its substitution for other forms of energy is one of the policy objectives of the government. Nepal's interconnected system's installed capacity has increased from 136 MW in FY1983 to 261 MW in FY1990, at an annual compound growth rate of 9.8 percent per annum. The hydroelectric capacity has grown at a much faster rate of 11 per cent during the same period. Most of the country's hydroelectric plants are of the run-of-the river type. The thermal capacity is entirely diesel based and its share in total installed capacity has declined from 18 percent in FY1983 to 11 percent in FY1990. Outside the interconnected system NEA operates several small, isolated hydroelectric and diesel plants. In FY1983, suitable amendments were made to regulations to permit the generation and sale of electricity by private producers. Table 1 gives details of trends in installed capacity in Nepal.

Table 1: Trends in Installed Capacity in NEPAL (MW)

Year	Hydro			Diesel	Total
	ROR	Storage	Total		
FY1983	51.05	60	111.05	25	136.05
FY1984	65.15	60	125.15	25	150.15
FY1985	65.15	60	125.15	25	150.15
FY1986	66.15	60	126.15	25	151.15
FY1987	98.15	60	158.15	25	183.15
FY1990	na	na	232.00	29	261.00

FY1983 - 16 July 1982 to 15 July 1983

NEC's total generation has increased from 291 GWh in FY1983 to 873 GWh in FY1991, registering a high growth rate of 14.7 percent per annum. In addition, Nepal imports power from India at 15 transfer points along the India-Nepal border in accordance with the agreement between the two governments reached in October 1971. The share of imports from India in the total availability of electricity has declined significantly over the years from 17.8 percent in FY1983 to a mere 3.2 percent in FY1990. Trends in electricity generation and system losses in NEC are given in Table 2.

Table 2: Trends in generation, sales and system loses in NEC

Fiscal year	Generation + imports from India (GWh)	Sales (GWh)	System losses (%)
FY1976	150	107	28.7
FY1980	229	162	29.3
FY1981	231	163	29.4
FY1982	268	184	31.3
FY1983	354	240	32.2
FY1984	383	256	35.2
FY1985	421	299	28.9
FY1986	489	341	30.3
FY1987	571	403	29.4
FY1988	629	465	26.1
FY1989	672	496	26.2
FY1990	771	548	28.9
FY1991	902	665	26.3

Total system losses including power station auxiliaries and non-technical losses have been high. Total losses as a percentage of gross generation plus imports/purchases reached a maximum of 33 percent in FY1984. Non-technical losses are due to pilferage, and meter reading and billing errors, while technical losses result from under investment in the distribution system, which causes overloading and wide voltage fluctuations. The share of investment in transmission to total investment in power sector has increased from 2.4 percent during Fifth Plan Period (1975-80) to 13.2 percent during Sixth Plan Period (1980-85), keeping in view the basic objective of reducing system losses. This share was 10.1 percent during the Seventh Plan Period (1985-90). (Refer Table 3 for details). As a result of there efforts to reduce the losses, the total system losses in FY1991 have come down to 26 percent.

Table 3: Percentage distribution of investment planned for different activities in the Plan Periods

	V Plan (1975-80)	VI Plan (1980-85)	VIII Plan (1985-90)
Large hydropower	88.7	69.2	56.8
Small hydropower	1.5	4.2	5.3
Transmission lines	2.4	13.2	10.1
Electrification & Systems improvement	1.7	9.7	9.5
Others	5.5	3.7	18.4

Power Market

During the period FY1984 to FY1991, peak demand on the Nepal interconnected system grew from 76 MW to 204 MW, averaging a growth rate of 15 percent per annum. The number of consumers and electricity sales (including exports to India) has grown at an annual growth rate of 13.8 percent and 14.6 percent respectively during the same period. The pattern of electricity consumption is shown in Table 4. The industrial sector experienced the fastest growth in electricity consumption from 78 Gwh in FY1984 to 147 Gwh in FY1987, averaging a growth rate of 23.5 percent per annum. Its share in total sales has increased from about 32 percent to 39 percent during the same period. The share of sales to residential consumers fluctuated between 42-45 percent and that of commercial sector declined from 19.5 percent to 13 percent during the same period. The large proportion of residential load result in pronounced morning and evening peaks. The annual peak demand occurs during the cold and dry months of December and January when hydropower generation is the lowest.

Table 4 : Trends in energy sales and peak demand

Year	Domestic	Commercial	Indy	Agri	Others	Exports	Total	Peak Demand
FY1984	101.4	48.1	78.3	10.9	7.8	10	256.5	76
	(41.1)	(19.5)	(31.8)	(4.4)	(3.2)	(3.9)		
FY1985	125.3	49.8	92.5	11.6	8.6	11	298.8	80
	(43.6)	(17.3)	(32.4)	(4.08)	(2.6)	(3.7)		
FY1986	141.0	50.5	110.7	12.8	5.1	21	341.1	110
	(44.1)	(15.8)	(34.6)	14.00	(1.5)	(6.2)		
FY1987	158.9	49.6	147.4	16.8	5.5	21	399.2	126
	(42.0)	(13.1)	(39.0)	(4.51)	(1.4)	(5.3)		
FY1988*							465.1	141
FY1989*							496.1	150
FY1990*							548.7	176
FY1991*							665	204

*Consumer category wise breakup not available

Tariff

A summary of the trends in electricity tariff is given in Table 5. In 1983 and 1984, there were steep increases in electricity tariffs, primarily to meet the revenue requirements set by the covenants of loan agreements with the World Bank and ADB. However, these tariff increases lead to increase pilferage and reduce demand growth, resulting in not much of an improvement in the revenue earning.

Average revenue per kWh of sales increased from NRs 0.55 in FY1983 to over Rs.1.38 in FY1990. Residential consumers, especially small consumers with monthly consumption upto 100 kWh, have been subsidized considerably. Consumers in the industrial and commercial categories pay a demand and energy charge. The seasonal variation in energy, availability results in dry season costs being 2-4 times the wet season costs, suggesting the need for a seasonal variation in tariffs. The high generating and supplying costs of electricity during peak hours also indicate the consideration should be given to introducing time-of-day tariffs.

Table 5: Nepal Electricity Corporation - Tariff

	NEC			NEA		Minimum
Tariff Category	Feb 1979	1983	1985	1988	Monthly charge	allowance (kWh)
Domestic Rs/kWh						
1-25 kWh1	6.25	11.00	11.00	0-2.5 Amp	9	25
26-100 kWh	0.40	0.70	0.90	2.5-15 Amp	30	25
101-300 kWh	0.55	0.80	0.90	16-30 Amp	60	50
300 kWh	0.70	0.90	1.10	30-60 Amp	90	75
				61-100 Amp	122	100
				> 100 Amp	412	300
Industrial Rs/kWh						
1-50 kW		.56	.75	400/220 Volt	1.25	
		(20.0)	(20.5)		(75.0)	
51-500 kW		.52	.70	11 KV	1.20	
		(45.0)	(49.0)		(70.0)	
				33 KV	1.10	
					(65.0)	
500 kW		.50	.57	66 KV	0.95	
					(60.0)	
Commercial (Rs/kWh)						
Hotels		.70	.95		1.60	
		(50.0)	(67.5)		(1.08)	
Others		.70	.95		1.65	
		(40.0)	(54.0)		(80.0)	
Irrigation					0.80	
					(20.0)2	

Figures in brackets indicate demand charges Rs/kW/month

1. Tariff regardless of consumption upto 25 kWh
2. Fixed charge Rs/kW/month

NEC, realized a positive net income in FY1983 and FY1984 and so did NEA in all the years from FY1986 to FY1990. In FY1985, NEA incurred a net loss with a negative rate of return of .6 percent. The operating ratio of both NEC and NEA have been below one except for in FY1985 when, the total expenses exceeded the total revenue earned during that period. Some of the important financial indicators are highlighted in Table 6.

Table 6: Financial indicators of NEC/NEA

Ratio	FY1983	FY1984	FY1985	FY1986	FY1987	FY1988	FY1989	FY1990
Operating Ratio	0.98	0.80	1.05	0.62	0.68	0.78	0.87	0.82
Debt/equity ratio	0.07	0.08	1.24	0.80	0.83	0.43		
Debt Service Ratio	6.37	3.29	0.54	1.47				
Self Financing Rate	0.28	0.28	0.03	0.17				
Rate of Return (%)	1.30	2.48	0.60	5.39				

Future strategy

Nepals' long term objective is to develop its enormous hydropower resources for domestic use and for export, thereby increasing its export earnings to finance overall economic development programs. Associated with this is the urgent need to substantially reduce the cost of power produced in Nepal, so that a greater shift to electricity by households, industry and agriculture can take place. Hydropower development till date has focused on meeting short term domestic requirements with relatively small and high-cost run-of-river projects. The policy of limiting power development to the domestic market has ruled out medium size projects of 300-500 MW or higher because the small size of the domestic market could not absorb all of the power produced during the initial years of the projects life. For Nepal to achieve cheap energy, it would have to take advantage of economies of sale by building larger plants, some of which would have to be storage type, firm up other run of river plants and expand the present power exchange agreement with India so that Nepal can export power in excess of domestic needs.

PAKISTAN

Institutions and organisational structure

The responsibility of power supply in Pakistan rests with the power wing of Water and Power Development Authority (WAPDA), a Government owned statutory body, and the Karachi Electric Supply Corporation (KESC). KESC has been in existence for over 70 years as a joint stock company registered under the Companies Act of Pakistan. About 70 percent of its shares are held privately, while the remaining shares are held by banks, insurance companies and investment houses. KESC is responsible for generation, transmission and distribution of power in Karachi and its environs, while WAPDA caters to the power needs of the rest of the country. WAPDA and KESC grids are interconnected over a double circuit 220 KV line and two single circuit 132KV lines with a combined capacity of 940 MVA. However, WAPDA and KESC operate their respective systems largely independent of one another and power system planning is done separately. The Nuclear power plants are operated by the Pakistan Atomic Energy Commission (PAEC).

The Ministry of Water and Power formulates power sector policies, allocate resources, and approves all major investment decisions as well as tariff revisions, in consultation with the Ministry of Finance and the Ministry of Planning and Development.

Supply System

As of 30th June, 1990, WAPDA had an installed generating capacity of 2897 MW of hydroelectric (45.2 percent), 1602 MW of coal fired (25.0 percent) and 1912 MW of oil or gas (29.8 percent capacity. Other than thermal based capacity of KESC, power supply in Karachi areas is supplemented by 125 MW nuclear station owned by PAEC, and 2x50 MW steam turbines. During the period 1983 to 1990, WAPDA's total installed capacity has grown at an average annual rate of 7 percent. Over the years, the hydro-thermal capacity mix has shifted towards thermal based power plants; the share of hydroelectric capacity operated by WAPDA declined from nearly 64 percent at the end of FY1983 to about 45 percent in FY1990 (refer Table 1 for details).

During the period (FY1980 to FY1990) the gross energy generation of WAPDA, has increased at an annual compound growth rate of 10 percent. Share of hydroelectricity has declined from about 72 percent in FY1980 to 54 percent in FY1990. Owing to variations in water flows and irrigation requirements, as well as to limitation of reservoir size, generation from hydropower projects declines considerably in the dry season. During the dry season, available capacity is much below the annual peak, resulting in frequent power supply interruptions. This has prompted several consumers to install standby diesel generators. During the period 1983-1987, Electricity generation by KESC, grew at a faster rate of 12.2 percent per annum as compared to WAPDA which had a growth rate of 9.1 percent during the

same period (Table 2 gives the trends in electricity generation in WAPDA and KESC.

Table 1 : Trends in installed capacity (MW)

Year	WAPDA				KESC
	Hydro	Coal	Gas	Total	
1983	2547	954	485	3986	928
1984	2547	954	485	3986	1138
1985	2897	954	485	4336	1138
1986	2897	1164	885	4946	1138
1987	2897	1125	1327	5349	1108
1990	2897	1602	1912	6411	n.a.

Table 2: Trends in generation and system losses in WAPDA and KESC

Fiscal Year	WAPDA					KESC	
	Hydro generation	Thermal generation	Imported electricity	Total supply	System losses (%)	Generation (GWh)	System losses (%)
1980	8718	3390	16	12124	32.70		
1981	9046	4157	3	13206	31.33		
1982	9526	5208	34	14768	30.34		
1983	11366	5121	5	16492	29.74	3001	25.57
1984	12822	5193	37	18052	29.30	3550	24.76
1985	12245	5858	674	18777	26.74	4528	22.23
1986	13804	6780	471	21055	26.36	4583	21.88
1987	15251	8188	191	23630	24.90	4772	22.66
1988	16689	10646	116	27451	24.59		
1989	16974	11892	32	28898	23.93		
1990	16925	14237	264	31426	23.25		

Total power losses in the WAPDA system, including station use and T & D losses, declined considerably during the past decade, from 32.7 percent in FY1980 to 23.2 percent in FY1990. An improvement in the maintenance and operation procedures of thermal power plants (supported by ADB, the World Bank and USAID) helped to reduce the auxiliary consumption levels to about 2 percent of gross generation by FY 1987. Adoption of a higher voltage for long-distance transmission and construction of 500 KV and 220 KV lines (with financing from ADB, the World Bank and other bilateral sources) helped to moderate transmission losses. In addition, WAPDA also mounted a drive against non-technical losses in the distribution network, amending laws to

facilitate easier prosecution of those who pilfer electricity as well as to make punishment more severe. WAPDA also improved its metering methods by providing anti-theft boxes and special seals and adopted measures to increase the effectiveness of its surveillance teams to detect fraud and prosecute offenders. Efforts will continue to be made to reduce WAPDA's, technical distribution losses (estimated at about 60 percent of the utility's total losses) through the distribution rehabilitation component of ADB's Tenth Power Sector Loan approved in December 1986.

Power market

During the ten year period 1980-90, energy sales in the WAPDA areas, grew from 8160 GWh to 24,121 GWh registering an average annual growth rate of 11.4 percent. However, except for the domestic sector, there has been no major change in the share of electricity consumption by the other consumer categories, during the ten year period 1980-1990. The share of electricity consumed by domestic sector has increased more than one and a half times from 19.2 percent in 1980 to 31.1 percent in 1990. The rapid rate of growth in this sector 17 percent per annum is due to the money boom, increased use of domestic appliances and air-conditioning, all given impetus by remittances from the Middle East. The share of industries and agriculture sector has gone down by 10 percent and 18 percent respectively during the same period. The share of commercial sector has fluctuated between 4-5 percent. Table 3 gives the categorywise break up of electricity consumption by consumers served by WAPDA.

Table 3: Category wise consumption WAPDA (GWh)

Year	Domestic	Commercial	Industrial	Agriculture	Others	Total
FY1980	1564	389	3154	2056	997	8160
FY1981	1858	445	3482	2125	1158	9068
FY1982	2408	374	3960	2357	989	10288
FY1983	2866	634	4417	2546	1124	11587
FY1984	3470	739	4708	2663	1182	12762
FY1985	3888	796	5061	2782	1229	13756
FY1986	4514	875	5894	2880	1341	15504
FY1987	5357	991	6436	3452	1509	17745
FY1988	6290	1054	7236	4394	1728	20702
FY1989	6939	1068	7579	4357	2039	21982
FY1990	7505	1105	8310	5004	2197	24121

In the KESC service area, the number of consumers increased at the rate of 7.8 percent per annum and electricity sales increased at the compounded growth rate of 12.5 percent per annum. Industries account for the major share of electricity sales by KESC followed by domestic consumers. The share of agriculture sector is almost negligible. (Refer table 4 for details).

Table 4: Category wise consumption, peak load and number of consumers - KESC

Year	Domestic (GWh)	Commercial (GWh)	Industrial (GWh)	Agriculture (GWh)	Others (GWh)	Total (GWh)	Peak load (MW)	No. of consumers
1983	929.31	501.15	1035.83	12.90	100.08	2579.27	618	610.55
	(36.03)	(19.43)	(40.16)	(0.50)	(3.88)			
1984	1096.41	558.76	1189.88	13.27	157.10	3015.42	732	649.71
	(36.36)	(18.53)	(39.46)	(0.44)	(5.21)			
1985	1203.46	578.62	1256.24	13.10	800.89	3852.31	797	701.45
	(31.24)	(15.02)	(32.61)	(0.34)	(20.79)			
1986	1360.95	650.55	1401.78	19.81	610.12	4043.22	872	765.15
	(33.66)	(16.09)	(34.67)	(0.49)	(15.09)			
1987	1482.34	722.79	1559.98	19.00	346.11	4130.22	945	823.74
	(35.89)	(17.50)	(37.77)	(0.46)	(8.38)			

Figures in bracket are percent share

Tariffs

The WAPDA Act (Act XXXI of 1958) requires that WAPDA's tariffs recovers all its operating costs (including depreciation and taxes and duties), service its debt and earn a reasonable rate of return. WAPDA's average tariff per unit increased from PRs 0.19 in FY1975 to PRs 0.94 in FY1989 at an average annual rate of 12.0 percent.1/ The annual growth rate of the average tariff during FY1985 to FY1989 was slightly lower at 10.3 percent. Tariffs are usually reviewed annually and an effective as of 1 July of each year.

The existing tariff schedule of WAPDA adopts increasing block tariffs for domestic and commercial consumers. For others a capacity charge based on connected load and an uniform energy charge are adopted. The tariff includes provisions for penalties for poor power factor (below .85) and late payment of bills. Private tube wells have an optional monthly flat rate tariff based on the horsepower rating of the pumpset.

WAPDA's fuel adjustment charge (FAC) is determined at the beginning of each financial year and is estimated by dividing the projected fuel expenses for the coming financial year by the projected energy sales (kWh) to all consumer during that financial year. Domestic consumers with consumption in the range of 151 - 300 kWh per month pay only 10 percent of the FAC and those with consumption less than 151 kWh per month are exempt from FAC. WAPDA's latest tariff structure is given in Table 5.

1/It is noteworthy that GDP Implicit Price Deflator grew at an average annual rate of 8.3 percent during FY 1975 - FY 1989 FY1989.

Table 5: WAPDA, tariff schedule, with effect from 1st July 1990

Category	Unit charge	Minimum charge	Fuel adjustment
Domestic	0-50 kWh -51 p/kWh 51-150 kWh -67 p/kWh 151-300 kWh -75 p/kWh 301-1000 kWh -101 p/kWh >1000 kWh -134 p/kWh	10 PRs	Applicable to slabs 4 and 5 slab 3 pays 10 percent of fuel adjustment charge
Commercial	0-100 kWh -196 p/kWh >100 kWh -218 p/kWh	34 PRs	Applicable
Industrial			
I1 - Single phase 230 V, or 3 phase 400 V			
	0-20 kW C.L. - 108 p/kWh	PRs 38/kW/Month	Applicable
	20-70 kW C.L. - 108 p/kWh	PRs 49/kW/Month	
	70-500 kW C.L. - PRs 138/kW/Month of declared load + 68 p/kWh	PRs 138/kW/Month	
I2 - Supply at 11 kV & 33 kV	PRs 134/kW/Month of declared load + 61 p/kWh	PRs 134/kW/Month	Applicable
I3 - 66 kV or 132 kV	PRs 131/kW/Month of declared load + 56 p/kWh	PRs 131/kW/Month	Applicable
Agriculture			
A1 - Punjab and Sind	45 p/kWh	PRs 38/kW/Month	
A2 - NWFP and Baluchistan	32 p/kWh	PRs 34/kW/Month	

WAPDA's tariffs need to continue the trend of improvement in levels together with some rebalancing of structures to bring them more into line with marginal costs of supply to the different consumer categories. Tariff levels and structure needs to be rationalized to meet the objectives of load management, peak and off-peak tariffs, interruptible supply tariffs and seasonal tariffs. In 1985, WAPDA with the assistance of ADB carried out a load management study which recommended tariff modifications to reflect time-of-use for large industrial/commercial consumers and interruptible tariffs for agricultural consumers. A time-of-use metering study was indicated by WAPDA in 1989 which is expected to be completed in FY1991. The study will determine the impact of time-of-use tariffs on the 500 largest industrial and commercial consumers and on the peak generation demand.

Financial performance

Some of the important financial indicators for the period 1985-1990 of WAPDA are highlighted in Table 6. It is evident that WAPDA's financial indicators have remained sound throughout the period. Return on rate base had increased from 11 percent in FY1985 to 20.6 percent in FY1990. Satisfactory performance during this period has been largely determined by WAPDA's efforts to achieve ADB's requirement for a minimum 40 percent self-financing of three year (previous current and succeeding) average capital expenditure. The relatively less satisfactory results in FY1985 and FY1987 were caused by unfavourable hydrology which necessitated a sharp increase in thermal generation. The resulting high fuel cost was not adequately recouped by the predetermined fuel adjustment charge.

Table 6: Financial indicators summary - WAPDA

	1985	1986	1987	1988	1989	1990a/
Operating ratio	0.70	0.65	0.68	0.66	0.60	0.54
Return on rate base (%)	11.10	13.60	10.50	13.10	16.90	20.60
Return on equity (%)	6.10	9.90	6.30	9.70	13.60	16.00
Self financing - (3 yr avg)	34.30	43.40	33.70	41.60	37.90	50.00
Debt service coverage (times)	1.60	1.70	1.40	1.60	1.80	1.60

a/Provisional
Source: ADB Appraisal of the WAPDA Eleventh Power Project in Pakistan, November 1990.

Long term power development plan

Based on the long term, least cost development plan, WAPDA's generating capacity is forecast to increase by over 80 percent during the seventh plan period (FY1989-FY1993), from 5550 MW in July 1988 to 10068 MW in June 1993. About 60 percent of this new generating capacity will be thermal, to help in overcoming the problem of capacity shortage during the low water release months from January to June when power generating capacity of hydroelectric plants is restricted. This increase in installed capacity together with associated T&D facilities are expected to cost about PRs 88 billion. Table 7 gives WAPDA's capacity addition programme during VII and VIII plan. For the Eighth Plan period (FY1994-FY1998), WAPDA plans to add 5844 MW capacity-an increase of 50 percent.

According to a demand forecast prepared in October 1990, energy demand is estimated to grow at a compounded annual growth rate of 9 percent per annum during the period FY1991 to FY1998. A comparison of the load forecast with WAPDA's power development

programme (refer Table 8) shows that FY1991 onwards supply can meet demand. An energy surplus of 12 percent is estimated for the FY1990.

Table 7: WAPDA's capacity expansion programme

Year	Thermal (MW)	Thermal (%)	Hydro (MW)	Hydro (%)	Total MW
1990	3516	54.8	2897	45.2	6413
1991	4160	58.9	2897	41.1	7057
1992	4780	53.3	4196	46.7	8976
1993	5240	52.0	4828	48.0	10068
1994	5640	53.9	4828	46.1	10468
1995	6540	57.5	4828	42.5	11368
1996	7497	59.5	5107	40.5	12604
1997	8997	61.2	5715	38.8	14712
1998	9697	60.9	6215	39.1	15912

Table 8: Comparison of forecast of energy demand and availability

Financial Year	Forecast Energy demand (Gwh)	Forecast Energy available (Gwh)	(+) Surplus (-) deficit (%)
1991	25971	26563	+2.3
1992	28616	29875	+4.4
1993	31115	34033	+9.4
1994	33877	35184	+3.9
1995	36933	37960	+2.8
1996	40273	45298	+12.5
1997	43974	49431	+12.4
1998	48132	54130	+12.5

Private sector participation in power sector

One of the main reasons for severe power shortages in Pakistan is the power subsector's inability to expand its supply capacity fast enough to keep up with the growing demand. One of the reasons for this is resource constraints. Share of public sector investments has increased almost two and a half times from 11.8 percent in the first five year plan (1995-60) to 28.7 percent in sixth five year plan (1983-88) and its further increase is limited. Thus, the Government of Pakistan introduced a new policy in 1985 allowing private sector participation in building and operating power plants which are elements of the country's least cost generating expansion plan, and selling power to the grid. Following this development, a programme was initiated to provide supplementary financing for private sector

projects. A "Private Sector Energy Development Fund" (PSEDF) was created to mobilize funds for lending to qualified private sector projects. The private power cell of the Ministry of Water and Power has so far received 17 private power project proposals with a total capacity of more than 5000 MW. Of these, the Ministry of Water & Power has issued letters of intent for six projects - 1915 MW.

SRI LANKA

Institutions and organisational structure

The Ceylon Electricity Board (CEB), a statutory corporation established in 1969, is the national power utility responsible for generation, transmission, rural electrification and a large share of distribution throughout the country. The CEB supplies power directly to consumers, and also sells in bulk to licensees (local authorities) which, in turn, retail power to their consumers. In 1983, the Lanka Electricity Company (Private) Limited (LECO) was established as a private autonomous company, to take over gradually the distribution system of some local authorities. Of the original 217 local authorities licensed to distribute electricity in Srilanka, 18 were taken over by LECO by early 1989.

The 1969 CEB Act gave CEB substantial autonomy, although the Government retained an important role in such policy matters as tariffs and investments, borrowings and appointment of Chairman and General Manager. Subsequent legislation and Government regulations have, however, reduced this. Several government ministries are involved in the power subsector. The ministry of Power and Energy is responsible for the supervision of CEB and LECO, while the Ministry of Administration, Provincial Councils and Home Affairs is in charge of the overall administration of the local authorities. The Mahawati Authority of Srilanka of the Ministry of Mahaveli Development is responsible for the implementation of power projects under the Accelerated Mahaveli Development Program (AMDP). The Ministry of Finance and the Ministry of Policy Planning and Implementation are also involved in the administration of the power subsector.

Supply system

The CEB's total installed generating capacity has increased from 361 MW in 1975 to 1289 MW in 1990, registering an average growth rate of 17.7% per annum. This increase was due largely to additions in hydroelectric capacity. With the increasing price of imported crude oil and the consequent strain on balance of payments, the primary emphasis in the energy sector has been on the development of hydropower. Three hydroelectric stations Victoria (210 MW), Kotmale (201 MW) and Randenigala (122 MW) - have been commissioned under the AMDP. By the end of 1990, hydropower stations accounted for 79 percent of CEB's total installed capacity. The remaining capacity consisted of steam turbines (50MW), gas turbines (128 MW) and diesel engines (94 MW), which are run during peaking and drought conditions. Trends in installed capacity is given in Table 1.

Total gross generation in CEB's power stations increased from 1078 GWh in FY1975 to 1872 GWh in FY1981 and further to 3150 GWh in FY1990. During the period 1981 to 1990, gross generation grew at an average annual rate of 5.9 percent. During the period FY1975 to FY1979, thermal generation was a negligible portion of total energy production, but it's share grew as installed thermal capacity

Table 1 : Trends in Installed capacity (MW)

Year	Hydro	Thermal	Total
1975	291	70	361
1977	331	70	401
1981	371	150	521
1982	371	190	561
1983	401	190	591
1984	471	250	721
1985	679	270	949
1986	801	264	1065
1987	801	270	1071
1988	965	220	1185
1989	968	272	1240
1990	1017	272	1289

increased in the early 1980s, and peaked in 1983 because of the severe drought. Hydropower generation reached a maximum of 2645 GWh in 1986, when it accounted for 99.7 percent of the CEBs total gross generation during that year. Because of drought year in 1987, share of hydropower generation declined to 80 percent However, once again in 1989, it's share rose to 99.8 percent (refer Table 2 for details).

Table 2: Trends in Gross generation

Year	Hydro	Thermal	Total
1975	1077	1	1078
1977	1215	2	1217
1981	1571	301	1872
1982	.1608	458	2066
1983	1217	897	2114
1984	2091	170	2261
1985	2395	69	2464
1986	2465	08	2653
1987	217	530	2707
1988	2597	202	2799
1989	2801	57	2850
1990	3145	05	3415

All the power station feed the national grid operating at 220 kV and 132 kV. The physical condition of the subtransmission and distribution network, is generally unsatisfactory as a result of high load growth, insufficient investment and inadequate maintenance. CEB's transmission and distribution losses, as a percentage of gross

generation (i.e. including station use) increased from about 10 percent in FY1975 to about 20 percent in 1981. The losses declined to 17.2 percent in FY1989. The principal cause of high losses is underinvestment in medium and low voltage lines, which results in overloading, poor voltage conditions and low power factors. These problems being addressed by CEB includes the following major components :

(i) construction of nearly 1200 CKt-km of 33 kV lines and about fifty 33kV switching stations

(ii) strengthening and upgrading about 500 kW of 11 kV lines

(iii) installing at least 50 MVA of capacitors, and 1200- 33 kV and 300 11kV distribution transformer stations. It is expected that these instruments will help reduce CEB's system losses to 12 percent by FY1992. Energy losses in CEB system are given in Table 3.

Losses in the distribution system operated by local authorities and LECO are generally high. In 1987, these losses were estimated to average 25 percent of CEB's bulk sales, comprising 10 percent technical losses and 15 percent non-technical losses. As with CEB, the principal cause of high technical losses in LECO is under investment in lower village distribution lines. LECO has substantially reduced these high losses in local authority systems it has taken over, to an average level of about 18 percent in 1988 and about 13 percent in 1989. Further reduction to about 10 percent is projected by 1993.

Table 3: Energy losses in Srilanka

Year	Station Use	Network	Total	Percent of generation
1975	06	107	113	10
1977	06	170	176	14
1981	17	352	369	20
1982	17	363	380	18
1983	21	301	322	15
1984	11	374	385	17
1985	11	411	422	17
1986	10	411	421	16
1987	15	439	454	17
1988	14	414	428	15

Source: ADB report, May 1990.

Electricity consumption in Srilanka increased at an average annual rate of about 5.8 percent during the period 1975-1981, and about 8.2 percent during the period 1981-1986. Due to civil disturbances and economic slowdown in the country average annual

growth rate of electricity consumption declined to 4 percent during the period 1986-1990. However, consumption by domestic and commercial consumers has grown at a much faster rate of 8.4 percent and 7.4 percent per annum respectively during the same period. Over the years, share of electricity sales to commercial sector has increased from 12.3 percent in 1975 to 17.1 percent in 1986 and further to 19.5 percent in 1990. High electricity consumption in the commercial and hotel sector is a result of boom in tourism and trading activities in the country. The share of electricity consumed by industries has declined from 54.2 percent in 1975, to 41.4 percent in 1980 and about 35 percent in 1990. Even in absolute terms the electricity sales to industrial sector has shown no significant increase and has fluctuated between 850 GWh to 926 GWh during the period FY1988 - FY1990. Electricity sales to local authorities and LECO has varied between 23 to 25 percent of the total electricity sales over the years. Details of sectoral consumption of electricity is given in Table 4.

Table 4: Sectoral consumption of electricity in SriLanka

Year	Domestic	Commercial	Industrial	Local Authority	Others	Total
1975	87	119	523	223	13	965
1977	107	148	520	252	14	1041
1981	217	220	678	381	08	1504
1982	258	262	739	418	09	1686
1983	305	292	752	433	10	1792
1984	316	300	791	458	11	1876
1985	347	350	850	502	12	2061
1986	369	382	925	543	133	2232
1987	382	419	866	522	15	2253
1988	405	443	906	601	16	2371
1989	408	436	849	631	29	2353
1990	496	508	910	657	36	2608

Tariffs

Tariff structure and rates proposed by CEB are approved by Cabinet after obtaining endorsement of the Ministry of Power and Energy and the Ministry of Finance and Planning. In the case of LECO and the local authorities, proposals must be authorized by the Government appointed Chief Electrical engineer. In practice most licensees adopt CEB's tariff structure with usually higher rates in the areas where the prevailing rates are already higher than the CEBs revised rates.

During the period 1972 to 1978, there was no increase in electricity tariffs in Srilanka, primarily because tariff was adequate to provide a reasonable operating surplus for the electricity board. Reluctance to increase the tariff however led to insufficient internal

resources which was a constraint to increasing proportion of investment requirements for the future. Thus in late 1978, electricity prices for different consumer groups were raised by about 80 percent. In addition, to recovering the costs of thermal power generation, which depend on unpredictable rainfall conditions, a fuel adjustment surcharge was also incorporated into the tariff structure.

In 1979 an LRMC study was initiated to examine tariff level and structure and major changes were introduced in the next tariff revision in 1982. These include a sharp increase in demand charge to cover the LRMC of capacity. The demand charge for industry which stood at Rs. 10/KVA was increased to Rs. 100/KVA. This revision increased the tariffs by about 90 percent, particularly for medium and large consumers. Drought conditions in 1983 increased the fuel adjustment charge to 185 percent.

In 1985 the basic tariffs were once again increased by nearly 100 percent over the basic tariff of 1982. This increase was necessary because of high inflation and currency devaluation that had occurred between 1980 and 1985. In real terms however, the tariff was maintained at 1981 level. An important feature of the tariff revision in 1985 was the introduction of an optimal time of day tariff for industry and hotels on a trial basis and the reduction of units allowed at concessionary rates for domestic consumers.

An important feature of next tariff revision in January 1988, was as much as 60 percent increase in the residential tariff for the lowest two consumption block, reducing significantly the relatively large subsidy on the first two tariff blocks. Secondly, the tariff adjustments were extended to enable LECO and local authorities to become financially viable without having to charge higher rates in line than those of CEB, in line with the Government's policy of uniform national retail electricity tariff. Although LECO's financial position improved with the 1988 tariff structure, it was not able to meet its financial targets for 1988-90.

A two year financial recovery plan has been prepared involving tariff adjustments in 1990-91. The first tariff adjustment, of about 38 percent on an average became effective in April 1990 and the second adjustment of 10 percent increase in tariffs in early 1991. The tariff structure of 1990, 1988 ad 1985 are compared in Table 5. The new tariff structure continues the programme of structural reforms, by limiting the residential subsidy to the first 50 kWh of monthly consumption, charging higher residential consumption rapidly increasing rates, improving the tariff margin to LECO, substantially increasing rates to industrial and commercial consumers and introducing a time of day tariffs to small industrial consumers.

Table 5: Comparison of tariff structures

	1985	1988	1990
Domestic Consumers		Domestic Consumers	Domestic Consumers
Unit Charge (Rs./Unit)	0 - 30 - Rs. 0.50/kwh 31 - 150 - Rs. 0.60/kwh 151 - 500 - Rs. 1.80/Kwh > 500 - Rs. 2.25/KWH	0-10 - Rs. 0.35/kwh 11-50 - Rs. 1.05/kwh 57-100 101-450 -Rs. 2.00/Kwh	0 - 10 - Rs. 0.55/kwh 11- 50 - Rs. 1.05/Kwh 51-100 - Rs. 2.00/Kwh 101-450 - Rs. 3.00/Kwh
Fixed Charge	Rs. 5/month	> 450 - Rs. 2.50/Kwh Rs. 5/Kwh	7450 - Rs. 4.00/Kwh Rs. 5/month for 1st
Fuel Adjustment Charge	--	Applicable to units in excess of 100 per month	Rs. 10/month for all other blocks applicable to units in excess of 50 per month

	1985 General Purpose	1985 Industrial	1985 Hotel	1988 General Purpose	1988 Industrial	1988 Hotel	1990 General Purpose	1990 Industrial	1990 Hotel
HT supply at 11 KV, 33 KV and 132 KV									
Demand Charge (Rs./KVA)	115.00	90.00	140.00	115.00	95.00	115.00	140.00	115.00	140.00
Unit Charge (Rs./Unit)	1.50	1.25		1.50	1.80	1.50	1.75	2.95	2.15
Fixed Charge (Rs./month)	200.00	200.00		200.00	200.00	200.00	200.00	240.00	240.00
Time of day ---: Off peak (Rs.limit)						1.45	1.45 5	2.00	
2.10 Peak (Rs. limit)					2.20	2.20		4.70	4.75
Demand (Rs KVA)					45.00	45.00		55.00	55.00

Source (i) ADB, May 1990 Report on Srilanka.
(ii) Energy policies in Asia; A comparative study

Long term power development plan

CEB's energy sales is estimated to grow at an average annual rate of 16.4 percent during the period 1991 to 2000. The maximum demand is projected to grow from 640 MW in 1990 to 1068 MW in 2000 A.D. registering growth rate of 5.3 percent per annum. In accordance with the least cost generation expansion plan for CEB, a total of 522 MW of capacity is planned to be added during the 10 year period 1991 to 2000. In view of the uncertainties with respect to future demand growth, hydro availability and performance of the existing diesel plants, coal plants with high capital cost and long gestation periods are postponed beyond the year 2000 and flexible diesel units and small and medium hydro projects are given priority. Table 6 gives details of CEB's least cost generation expansion plan for the period 1991-2000. Moreover due to retirement of 170 MW of installed capacity during this period, the net capacity addition is expected to be 343 MW.

Table 6: CEB's least cost generation expansion plan

Year	Hydro (MW)	Coal (MW)	Diesel & Oil	Total (MW)
1991	49	-	50	99
1992	-	-	-	-
1993	120	-	-	120
1994				
1995				
1996	-	-	40	40
1997	-	-	40	40
1998	72	-	-	72
1999	-	-	40	40
2000	111	-	-	111
Total	352		170	522

CEB's total investment requirements in power system development for the period 1990-96 to meet the projected demand are estimated at about Rs.46 billion, with a foreign exchange component of about 53 percent The size and mix of investment programme is shown in Table 7.

Both CEB and LECO are making substantial investments in distribution. In order to co-ordinate future distribution expansion in Srilanka, a "National Power Distribution Master Plan", completed in 1989, recommends takeover by CEB of most of the local authorities scattered through out the country and decentralization of CEBs distribution functions into increasingly independent distribution organizations.

Table 7: CEB's investment programme 1990-96

	Rs. Million	% of total investment
Generation	21844	46
Transmission	5069	11
Distribution	16348	36
(of which Rural electrification)	(7711)	(17)
Other	3203	7
Total	46464	100

In Srilanka, only 25 percent of households and about 20 percent of villages have been electrified as in 1990, and electricity

has yet to be provided to about 20,000 villages. At this level of rural electrification, Srilanka is behind most developing countries. In the past, financing for rural electrification has been provided as equity to CEB, either directly from the Government or through the decentralized budget system. CEB has not used its own resources for rural electrification, nor has CEB been required to borrow funds for this purpose. This approach and strict adherence to achieving CEBs financial targets have moderated the pace of electrification and probably explain to a large extent the relatively low electrification rated in Srilanka.

Role of pricing:

To the economy: ensure optimal allocation of resources

To the producer: - get a fair rate of return
- also to generate a surplus for part-financing future additions to capacity

To the consumer: requires energy of desirable quality at lowest cost.

In addition prices can be set to:

- reduce dependance on foreign sources
- control foreign exchange-trade deficits/imbalances
- priority development of special regions
- preserving environment
- demand management (incl. cross-substitution)
- providing for basic energy needs of the economically backward

Finally - note: stability of prices
ease of administering them.

Formulation of pricing policies is a two stage process:

1. A set of ideal or first best prices which strictly meet the economic efficiency criterion is drawn-up.

2. Adjustments are made to meet other objectives

In the first stage, we begin with setting

$$P = MC$$

ie. price equals marginal costs.

For coal, oil/gas products, strictly speaking, in addition to calculation of marginal costs, one would have to consider border prices; i.e. option of importing vs producing. This would then be studied in the context of other non-economic objectives/ constraints.

- TWO BROAD COMPONENTS OF MARGINAL COSTS OF GENERATING AND SUPPLYING ELECTRICITY ARE :

  (A) CAPACITY COSTS

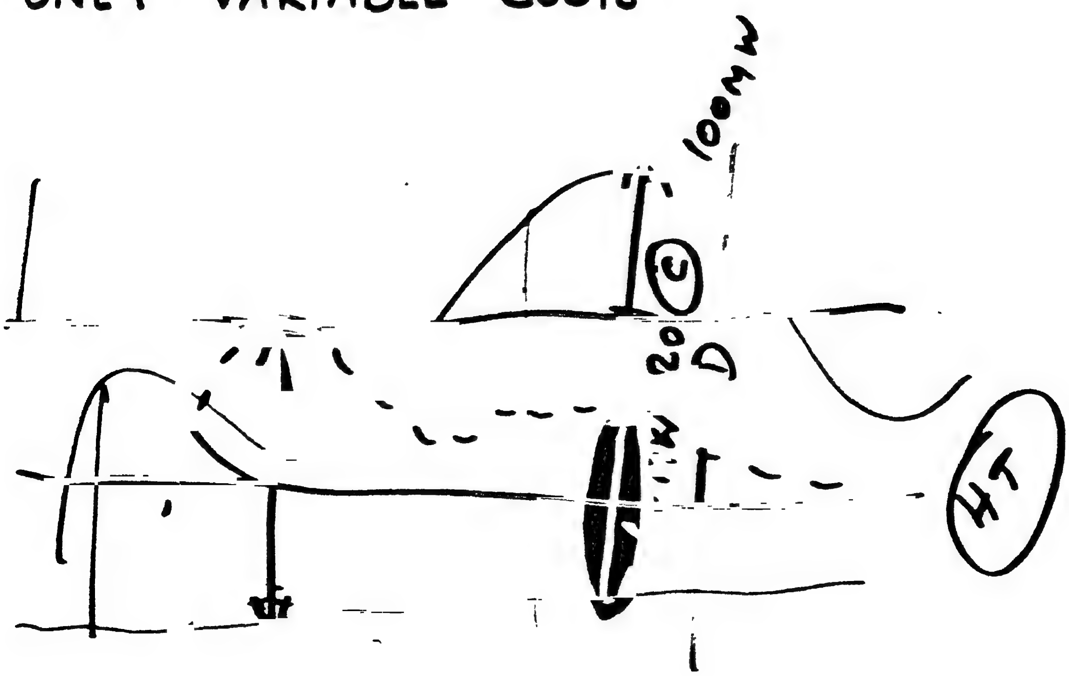
  (B) VARIABLE COSTS i.e FUEL, OPERATING AND MAINTENANCE COSTS

- USERS DURING PEAK PERIODS SHOULD PAY :

  CAPACITY COST AND VARIABLE COSTS

- USERS DURING OFF-PEAK PERIOD SHOULD PAY

  ONLY VARIABLE COSTS



- TO CALCULATE MARGINAL CAPACITY COST IT IS ESSENTIAL TO KNOW THE LONG TERM GENERATION/CAPACITY ADDITION PLAN, AND RELATED INVESTMENT PLAN.

- THE INVESTMENT PLAN SHOULD BE OPTIMAL — i.e LEAST COST.

- WHILE THE OFFICIAL POLICY FOR POWER SECTOR PLANNING IN INDIA, IS TO OPTIMISE AT REGIONAL LEVEL, TARIFFS ARE ESSENTIALLY CALCULATED AT THE STATE LEVEL.

  SINCE THERE ARE NO OPTIMISATION RUNS CARRIED OUT AT THE STATE LEVEL, THE TARIFFS WOULD INEFFECT BE CALCULATED BASED ON SUBOPTIMAL CAPACITY ADDITION PLAN.

$$LRMC = \frac{\sum_{t=1}^{n} \frac{I_t + (M_t - M_{t-1})}{(1+r)}}{\sum_{t=1}^{n} \frac{D_t - D_{t-1})}{(1+r)^t}}$$

where,

I_t = ANNUTISED INVESTMENT IN YEAR 't'

M_t = FIXED OPERATING COST IN YEAR 't'

D_t = DEMAND IN PERIOD 't'

r = DISCOUNT RATE

n = NUMBER OF YEARS

- MARGINAL ENERGY COSTS ARE THE FUEL AND OPERATING COSTS OF PROVIDING ADDITIONAL UNIT OF ELECTRICITY

- THE LONG RUN MARGINAL COST OF ENERGY DURING PEAK PERIOD IS THE RUNNING COST OF THE MACHINES TO BE USED LAST IN THE MERIT ORDER TO MEET INCREMENTAL PEAK DEMAND.

- LONG RUN MARGINAL COST OF ENERGY DURING OFF PEAK PERIOD IS THE RUNNING COST OF THE LEAST EFFICIENT ([illegible]) BASE LOAD PLANTS USED DURING THIS PERIOD.

$$LRAIC(i) = \frac{LRAIC(i-1)}{1 - LF(i, i-1)} + CAP(i, i-1)$$

$$\text{for } i = 2 \ldots\ldots V$$

Where,

LRAIC(i) = INCREMENTAL CAPACITY COST AT VOLTAGE LEVEL i

LF (i, i-1) = LOSS FACTOR FOR TRANSMITTING POWER BETWEEN VOLTAGE LEVELS i AND $(i-1)$

CAP (i, i-1) = MARGINAL COST OF TRANSMISSION CAPACITY BETWEEN VOLTAGE LEVELS i AND $(i-1)$

V = NUMBER OF VOLTAGE LEVELS BEFORE SUPPLY REACHES THE CONSUMER WHO IS SUPPLIED AT THE LOWEST VOLTAGE.

$$TARE(i) = \frac{PE(i) * PER(i) + OPE(i) * OPER(i) + MD(i) * MDR(i)}{[PE(i) + OPE(i)]}$$

where for category i,

TARE(i) = AVERAGE ENERGY RATE

PE(i) = PEAK ENERGY CONSUMED

OPE(i) = OFF PEAK ENERGY CONSUMED

PER(i) = PEAK ENERGY RATE

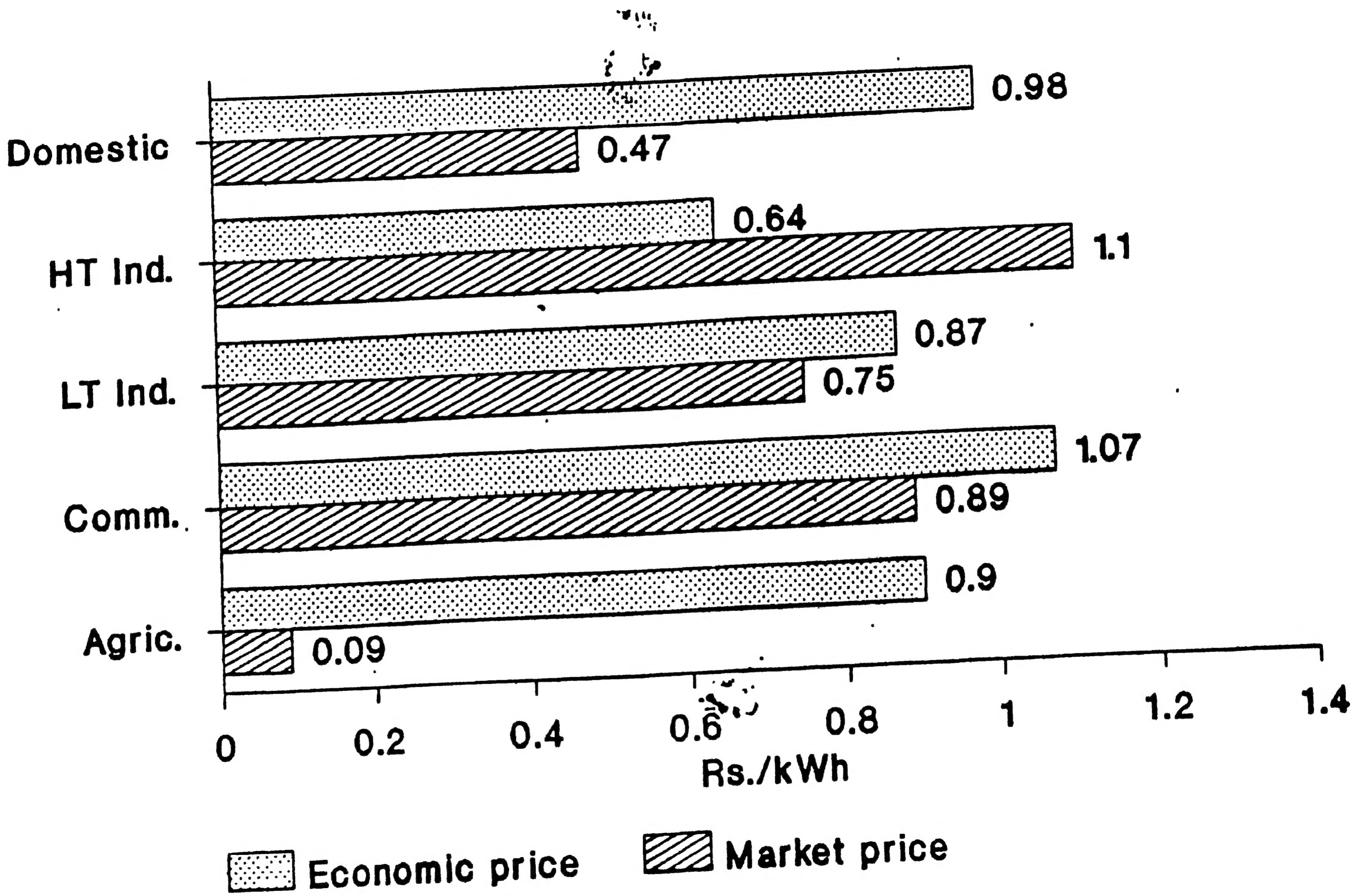
OPER(i) = OFF PEAK ENERGY RATE

MD(i) = MAXIMUM DEMAND DURING SYSTEM PEAK HOURS

MDR(i) = MAXIMUM DEMAND RATE

	DOM.	COMM.	LT-IND.	AGRI.	HT-IND.
PEAK ENERGY (KWh)	0·44	1·26	12·06	2·89	2770·38
PEAK ENERGY RATE (Rs/KWh)	0·78	0·78	0·78	0·78	0·69
OFF-PEAK ENERGY (KWh)	1·01	2·35	30·52	7·96	8002·33
OFF-PEAK ENERGY RATE (Rs/KWh)	0·33	0·33	0·33	0·33	0·29
MAX. DEMAND (KW)	0·112	0·315	2·65	0·73	496·71
CAPACITY COST (Rs/KW)	6·68	6·68	6·68	6·68	5·43
TARIFF (Rs/KWh)	0·98	1·07	0·87	0·90	0·64

Electricity prices
Economic vs. market



- ENERGY RATE
  - AV. ENERGY RATE
  - DECLINING BLOCK RATES
  - INVERTED BLOCK RATES
  - TIME-OF-DAY RATES
  - SEASONAL RATES
  - BULK RATES

- DEMAND RATES
  - NORMALLY BASED ON MAXIMUM DEMAND/KW
  - ALSO BASED ON SANCTIONED LOAD
  - TIME DIFFERENTIATED RATES
  - SEASONAL RATES
  - FLAT RATE/h.p.

- POWER FACTOR CORRECTION
  - PENALTY FOR HAVING PF BELOW LIMIT
  - INCENTIVE FOR HAVING PF ABOVE LIMIT

CONTENTS OF A TARIFF PACKAGE

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